ALBERTA

ENERGY RESOURCES CONSERVATION BOARD

DECISIONS

1982

NUMBER	APPLICATION NUMBER	TITLE	DATE OF ISSUE
82-1	810898	REPROCESSING PLANT - EMPRESS AREA EMPRESS LIQUIDS PROCESSING JOINT VENTURE	6 JANUARY 1982
82-2	810629, 810630, 810631 AND 810584	PERMIT TO CONSTRUCT PIPELINES - STOLBERG - RICINUS AREAS AQUITAINE COMPANY OF CANADA LTD. GULF CANADA RESOURCES INC. NOVA, AN ALBERTA CORPORATION	21 MAY 1982
82-3	810092	JUMPING POUND GAS PROCESSING PLANT SHELL CANADA RESOURCES LIMITED	7 APRIL 1982
82-4	810576	PERMIT TO CONSTRUCT THE GRAHAM LATERAL AND METER STATION - PRIMROSE AREA NOVA, AN ALBERTA CORPORATION	26 JANUARY 1982
82-5	810042 AND 810043	CHLORINE AND CAUSTIC SODA PLANT EXPANSION ETHYLENE DICHLORIDE AND VINYL CHLORIDE-MONOMER PLANT EXPANSION DOW CHEMICAL CANADA INC.	22 MARCH 1982
82-6	811007 AND 811008	PERMITS TO CONSTRUCT OIL PIPELINES - NORTHEAST EDMONTON AREA ALBERTA ENERGY COMPANY LTD.	2 FEBRUARY 1982
82-7	810465	PERMIT TO CONSTRUCT A PIPELINE - OKOTOKS TO CAYLEY CANADIAN WESTERN NATURAL GAS COMPANY LIMITED	9 FEBRUARY 1982
82-8	810696	GAS REMOVAL PERMIT APPLICATION SULPETRO LIMITED	15 FEBRUARY 1982
82-9	810514 AND 810999	PERMITS TO CONSTRUCT PIPELINES - WEST PEMBINA AREA AMOCO CANADA PETROLEUM COMPANY LIMITED PEMBINA PIPE LINE COMPANY LTD.	19 FEBRUARY 1982
82-10	810882	COMPULSORY POOLING - ELNORA FIELD ASHLU EXPLORATION LTD.	5 MARCH 1982

DECISIONS

NUMBER	APPLICATION NUMBER	TITLE	DATE OF ISSUE
82-11	810417	PROPOSED DEEP-CUT FACILITIES - JUDY CREEK AREA GAS PROCESSING PLANTS ESSO RESOURCES CANADA LIMITED	29 MARCH 1982
82-12	810520	QUIRK CREEK GAS PROCESSING PLANT ESSO RESOURCES CANADA LIMITED	7 APRIL 1982
82-13	810365	TARGET AREA CHANGE QUARTER SECTION DRILLING SPACING UNITS OSTRACOD OIL PRODUCTION - MEDICINE RIVER FIELD PEMBINA PIPE LINE LTD.	7 MAY 1982
82-14	810608 AND 810733	240-KV TRANSMISSION LINE FACILITIES IN THE LOUISE CREEK-SAGITAWAH AREA ALBERTA POWER LIMITED TRANSALTA UTILITIES CORPORATION	27 MAY 1982
82-15	810650 AND 810849	GAS PROCESSING PLANTS CANTERRA ENERGY LTD. GULF CANADA RESOURCES INC.	12 MAY 1982
ADDENDUM 82-15	810650 AND 810849	RAM RIVER GAS PROCESSING PLANT STRACHAN GAS PROCESSING PLANT CANTERRA ENERGY LTD. GULF CANADA RESOURCES INC.	10 JUNE 1982
82-16	810819	TO EXPAND THE BOUNDARIES - ELECTRIC DISTRIBUTION SYSTEM SERVICE AREA THE CITY OF EDMONTON (EDMONTON POWER)	21 MAY 1982
82-17	811041, 820204 AND 820205	SOUR GAS, FUEL GAS AND SALTWATER DISPOSAL PIPELINES - SHAW-MOUNTAIN PARK AREAS GULF CANADA RESOURCES INC.	18 MAY 1982
82-18	820150 AND 820218	REDUCE SIZE OF DRILLING SPACING UNIT - CHANGE TO 16 HA TARGET AREA IN ACCORDANCE WITH SU 800 - FOR A LICENCE TO DRILL A WELL IN LSD 15C-15-1-16 W4M LOMALTA RESOURCES LTD.	28 MAY 1982

NUMBER	APPLICATION NUMBER	TITLE	DATE OF ISSUE
82-19	820260 AND 820261	TO CONSTRUCT PIPELINES - OKOTOKS AREA MITCHELL ENERGY CORPORATION	19 JULY 1982
82-20	810982	WATERFLOOD CONCURRENT PRODUCTION APPROVAL REVIEW - MEDICINE RIVER OSTRACOD A POOL PEMBINA PIPE LINE LTD.	4 JUNE 1982
82-21	810434 AND 820033	APPROVAL OF A GAS PROCESSING PLANT AND RELATED GAS GATHERING FACILITIES - SILVER VALLEY AREA INVERNESS PETROLEUM LTD.	7 JUNE 1982
82-22	820083	PERMIT TO CONSTRUCT A GAS LINE - NORTHEAST EDMONTON AREA NORTHWESTERN UTILITIES LIMITED	7 JUNE 1982
82-23	820283	WELL LICENCE TO DRILL AN EXPLORATORY WELL - MILLARVILLE AREA GULF CANADA RESOURCES INC.	8 JUNE 1982
82-24	820250	LICENCE TO DRILL A WELL IN THE MAZEPPA FIELD - HIGH RIVER AREA BLAKE RESOURCES LTD.	16 JUNE 1982
82-25	PROC. 820395	COMPULSORY POOLING ORDER - ORDER NO. P16 CIGOL BIGLK 11-15-53-26 ST. ALBERT BIG LAKE FIELD	15 JUNE 1982
82-26	810959	AN ORDER DIRECTING THE PROPORTIONS OF GAS TO BE PURCHASED - BRAZEAU RIVER ELKTON-SHUNDA A POOL CANADIAN SUPERIOR OIL LTD.	29 JUNE 1982
82-27	810916 AND 811009	PROPANE EXTRACTION PLANT - FORT SASKATCHEWAN DOME PETROLEUM LIMITED FRACTIONATION PLANT - FORT SASKATCHEWAN CHEVRON STANDARD LIMITED	30 JUNE 1982

NUMBER	APPLICATION NUMBER	TITLE	DATE OF ISSUE
82-28	820114	PERMITS TO CONSTRUCT PRODUCT PIPELINES - NORTHEAST EDMONTON AREA SHELL CANADA LIMITED	12 JULY 1982
82-29	820498	INDUSTRIAL DEVELOPMENT PERMIT MANUFACTURE OF METHANOL FROM GAS BIEWAG ENERGY RESOURCES LTD.	1 OCTOBER 1982
82-30		NOT ISSUED	
82-31	810899	240/14.4-KV SUBSTATION - CASTLE DOWNS THE CITY OF EDMONTON	1 OCTOBER 1982
82-32	810998	EXPANSION OF EMPRESS GAS REPROCESSING FACILITIES DOME PETROLEUM LIMITED	19 OCTOBER 1982
82-33	820258	COMPULSORY POOLING - NORRIS FIELD VOYAGER PETROLEUMS LIMITED	13 SEPTEMBER 1982
82-34	820371	240-KV TRANSMISSION LINE LAMOUREUX TO DEERLAND AND DEERLAND SUBSTATION - FORT SASKACHEWAN AREA TRANSALTA UTILITIES CORPORATION	29 OCTOBER 1982
82-35	820949	SECONDARY NATURAL GAS PIPELINE - CALMAR AREA PASSBURG PETROLEUMS LTD.	25 NOVEMBER 1982
82-36	820244	FOR AN EXPERIMENTAL IN SITU OIL-SANDS SCHEME - BONNYVILLE AREA ALBION PETROLEUM CORPORATION LTD.	3 DECEMBER 1982
82-37	820229	INDUSTRIAL DEVELOPMENT PERMIT TO MANUFACTURE AMMONIA AT KATHLEEN PEACE RIVER FERTILIZER INC.	7 DECEMBER 1982
82-38	810543, 810606, 810376 AND 810377	GAS PLANT APPROVAL AMENDMENTS - PIPELINE PERMITS PINCHER CREEK AREA SHELL CANADA RESOURCES LIMITED GULF CANADA RESOURCES INC.	31 DECEMBER 1982

NUMBER	APPLICATION NUMBER	TITLE	DATE OF ISSUE
82-39	820308	APPROVAL OF A SOLUTION GAS PROCESSING PLANT - ST. ALBERT AREA AMOCO CANADA PETROLEUM COMPANY LTD.	22 DECEMBER 1982
82-40	821059 AND 821060	TO REINSTATE WELL LICENCE NUMBERS 97997 AND 97998 SUNCOR INC.	12 JANUARY 1983
82-41	820940	PERMIT TO CONSTRUCT PIPELINES - HEART RIVER AREA NOVA, AN ALBERTA CORPORATION	15 DECEMBER 1982

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

THIRD PARTY DAMAGE TO PIPELINES
OF UNION OIL COMPANY OF CANADA LTD.
IN THE CUTBANK AREA

Inquiry Report
Proceeding 820289

1 INTRODUCTION

1.1 The Incidents Leading to the Inquiry

Permit No. 19413 was issued to Peace Pipe Line Ltd. (Peace Pipe) on 19 October 1981, and amended on 4 December 1981, for the construction of some 33 kilometres (km) of 114.3 millimetre (mm) outside diameter (OD) pipeline from Lsd 7-16-62-8 W6M to Lsd 15-18-63-5 W6M. The construction was undertaken by Dome Petroleum Limited (Dome). Leduc Construction Company Ltd. (Leduc) was the contractor.

At approximately 10:30 am on 3 March 1982, an 88.9-mm OD flowline, licensed to and operated by Union Oil Company of Canada Ltd. (Union), was dented by a backhoe bucket in Lsd 7-6-63-5 W6M. The damage occurred while the backhoe was being used to expose two Union flowlines[1]. At about 2:30 pm on the same day in Lsd 15-7-63-5 W6M, an 88.9-mm OD Union flowline was hit and ruptured by a backhoe bucket while the backhoe was being used to expose it. The line was under a pressure of approximately 2800 kilopascals (kPa). A bulldozer operator was struck by flying debris and sprayed with oil. At about 5:30 pm on 5 March 1982, an 88.9-mm OD Union flowline was ruptured by a backhoe bucket while the backhoe was being used to expose two flowlines. The line had been depressured to approximately 280 kPa prior to the commencement of excavation.

1.2 The Inquiry

A public inquiry was called by the Energy Resources Conservation Board to determine:

- the events and conditions leading up to the breaks and the damage of the pipelines,
- the reasons for and cause of the pipeline breaks and damage,

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1 The location and date of the pipeline crossings are shown in the attached figure.

- the actions taken to notify the necessary authorities and affected parties, and
- the corrective actions taken to reinstate the operation of the damaged pipelines.

All principal participants in the incidents were required to attend.

The inquiry was held in Calgary, Alberta, on 27 May 1982, with V. E. Bohme, P.Eng., E. R. Brushett, P.Eng., and E. G. Fox, P.Eng., sitting. Those who appeared at the inquiry are shown in Table 1.

Table 1 THOSE WHO APPEARED AT THE INQUIRY

Principals and Representatives (Abbreviations used in Report)	Witnesses
Peace Pipe Line Ltd. (Peace Pipe) J. A. Ion, P.Eng.	J. A. Ion, P.Eng. B. Harris, P.Eng. N. R. Thomassen, P.Eng. J. W. Motley
Union Oil Company of Canada Ltd. (Union) J. Harris	J. Harris J. G. Vandermeer, P.Eng. D. W. Snyder, P.Eng. B. Goldie B. Pearson A. Magda D. Brown P. Pecharsky, P.Eng.
Leduc Construction Company Ltd. (Leduc) A. O. Ackroyd, Q.C.	R. Stevenson S. Reynolds P. Priestap M. Boily
Dome Petroleum Limited (Dome) W. M. Smith	P. J. Grant, P.Eng. A. Johnston J. Hartley of Hartley Petroleum Operators
Energy Resources Conservation Board staff (Board staff) C.J.C. Page M. J. Bruni I. M. Cameron, E.I.T.	J. D. Dilay, P.Eng. K. B. McMorris

The Board staff presented a submission which provided an account of the incidents based upon the best information available at the time, obtained through field inspection and discussions with representatives of the companies.

2 EVIDENCE AND VIEWS OF THE PARTICIPANTS

2.1 Peace Pipe

Peace Pipe stated that it had entered into an agreement with Dome, whereby the pipeline would be purchased from Dome after construction and testing was completed. In particular, Dome was responsible for providing Peace Pipe with the necessary information on foreign pipeline crossings. Peace Pipe's responsibility was limited to obtaining crossing agreements.

On 7 January 1982, Peace Pipe requested permission from Union to cross a pipeline in SE 1/4 6-63-5 W6M. On Peace Pipe's plan of crossing, the new pipeline right of way was shown with a limited section of the construction route, and thus, Union was not provided with a complete route of the pipeline. At Union's request, Peace Pipe revised the plan to show two flowlines in Union's right of way. Peace Pipe stated that it did not advise Dome and Leduc of the existence of two flowlines as the crossing agreement had not been completed.

Peace Pipe said it was aware of the initial incident on 4 March 1982, but did not inform the Board as it believed that the licensee of the damaged line was responsible for notification. Peace Pipe admitted that after the first incident, it was aware no crossing agreement was in place and the Pipeline Regulations had been contravened. It did not increase its inspections nor take action to determine other possible pipeline crossings. Peace Pipe stated that construction should not have commenced as there was no assurance of a crossing agreement.

In the matter of locating foreign pipelines, Peace Pipe was concerned with the difficulty in obtaining knowledge of the location of existing pipelines. It considered the Board's records incomplete and stated that it had not used them in the past. Peace Pipe suggested that the Board should consider including, from its records, plans of pipeline crossings as an attachment to permits issued in the future.

2.2 Union

Upon receiving the crossing application from Peace Pipe, Union said it reviewed the proposal with particular attention to the single crossing shown in the application and notified Peace Pipe that the crossing in fact involved two pipelines. Union did not request further information on the pipeline routing and stated that it was not aware of further crossings to the north. A formal crossing agreement was prepared and sent to Peace Pipe for signature on 9 March 1982. Union later received applications from Peace Pipe dated 23 April 1982 for the second and third crossings, although the flowlines at those locations had been ruptured on 3 and 5 March 1982, respectively.

According to Union, Dome and Leduc personnel approached a Union employee in the field on 2 March 1982 and requested Union to provide assistance in confirming Union rights of way and pipeline locations. They informed Union of the schedule to undertake the crossings but Union was not present to witness excavation. They advised Union that attempts had been made to hand expose the damaged lines.

The damaged lines were repaired immediately using replacement pipe given to Leduc by Union, but without a pressure test of either the pipe section or the entire line. Union believed that it did not have responsibility for ensuring testing requirements were met, and no discussions ensued between the parties with regard to pressure testing of the pipe.

Union stated that it notified the Board of the incidents several days after they occurred, once it became aware of all the facts. Section 36(1) of the Pipeline Act requires, when a leak or break occurs in a pipeline, that the permittee or licensee immediately cause the Board to be informed. Union stated that the wording of this section was ambiguous as both the permittee of a new line being constructed and licensee of an existing line appeared responsible for notification.

In Union's opinion, it is common practice within the industry to use Board records when searching for foreign pipelines. Union responded to Peace Pipe's suggestion that the Board provide plans to show foreign pipelines when permits are issued by stating that the operating companies must be responsible for collecting the necessary information and installing the new pipeline safely and that this responsibility should not be transferred to the Board.

In responding to questions regarding the cause of the incidents, Union believed the problem was based on a lack of communication within and between operating companies. Union stated that it should have been more concerned with the general activity in the area rather than just the single crossing shown in the application from Peace Pipe for a crossing agreement.

2.3 Leduc

Leduc stated that at the first crossing a flowline had been exposed and that, while the backhoe operator was extending the bellholes, a second line was contacted. Leduc was not aware that two flowlines existed in the Union right of way. At the second crossing, hand exposure was seen by Leduc to be impossible due to solid rock and frozen ground, and while scraping with a backhoe at a depth of about one metre, the line was ruptured. At the third crossing, Leduc said Union had indicated to it the presence of two lines before excavation commenced; however, it believed the second line was owned by Peace Pipe. As there was no confirmation of existence, Leduc assumed that only one flowline was in the right of way, and while extending the bellholes after exposing the first line, a second line was struck and ruptured.

Leduc was of the opinion that hand exposure is not always practical, such as at the second crossing but admitted that it would have been possible at the first and third crossings. Leduc stated that the requirements for hand exposure in the Pipeline Regulations appeared practical for most situations.

Leduc gave assurance that there were no time constraints on construction. There was full communication with Dome whereby Leduc's activities were well known. However, a Dome representative was present only for the third crossing.

With regard to the repairs of the damaged lines, Leduc believed that the owner of the line was responsible for supervising the repairs. Leduc was in agreement with Union that the incidents occurred in part due to a lack of communication on the project.

2.4 Dome

Dome accepted the responsibility designated by Peace Pipe to provide the locations of foreign pipeline crossings and said that it expected the surveyor to determine the existence of such crossings. The first crossing was determined prior to the survey of the proposed pipeline in October 1981. The second and third crossings were discovered during construction operations by Dome and Leduc personnel. Dome admitted that the status of the crossing agreements was not checked during construction and there was no communication with Union. Dome had no instructions from Peace Pipe with respect to crossing procedures and was not aware of Union requirements.

Although a Dome representative was not present during repairs to the damaged lines, Dome stated that it was in close contact with Leduc, and inspected the repairs. Dome notified Peace Pipe of the incidents, and assumed that Peace Pipe would notify the Board.

3 BOARD FINDINGS

3.1 Damage to Pipelines

During the construction of the pipeline, three Union flowlines were struck and two of them ruptured within a three-day period. The Board believes these incidents are evidence of a serious deficiency in the management of the project. It is clear that insufficient communication took place among all parties, particularly with regard to pipeline crossings.

3.2 Crossing Agreements

Peace Pipe failed to obtain crossing agreements prior to the commencement of excavation, thus the construction proceeded in contravention of Section 29(1)(a) of the Pipeline Regulations. Dome failed to ensure that crossing agreements had been obtained. Failure to adhere to this basic requirement was a key factor in the subsequent sequence of pipeline incidents.

3.3 Methods of Hand Exposure

Leduc failed to hand expose the pipelines using non-mechanical devices and failed to ensure that adequate precautions were taken during the crossing construction. In this regard, the Board believes that the requirements for hand exposure in the new pipeline legislation are reasonable, and had they been complied with in these instances, the problems encountered would have been minimized or perhaps avoided altogether.

3.4 Notification to the Board

Union failed to give notification of the incidents to the Board immediately as required by Section 36(1) of the Pipeline Act. However, the Board expects that the party who damaged the existing line should also take appropriate action to ensure notification of the Board. The intent of the section is that, where a leak or break occurs, the licensee of the affected line is to notify the Board. If the pipeline is under test, and thus has not yet been licensed, the permittee would provide the notification.

3.5 Pressure Testing of Pipeline Repairs

Union placed the repaired pipelines back in service although neither a pretest of the replacement pipe nor a pressure test of the entire line had been carried out, as required by Section 64(2) of the Pipeline Regulations.

3.6 Use of Board Records

The Board finds that the parties to the inquiry did not make full use of the Board's pipeline records. The Board believes its pipeline records to be a good information source for locating pipelines and expects companies to make every reasonable effort and use all available sources of information to locate existing pipelines. It is clear that this was not done in this instance.

3.7 Pipeline Legislation

The Board finds that the parties proceeded without regard for the Pipeline Act and Regulations and neglected to observe the requirements for:

- written crossing agreements,
- hand exposure of pipelines,
- immediate notification to the Board in the event of a pipeline break, and
- pressure testing of pipeline repairs.

4 CONCLUSIONS

The Board concludes that both Peace Pipe as permittee and Dome as construction supervisor demonstrated an unfortunate disregard for the Pipeline Act and Regulations and normal good pipeline practice in commencing construction of a pipeline without a thorough search for other pipelines to be crossed or obtaining crossing agreements. There appeared to be no extenuating circumstances to justify these lapses. In the case of Leduc, the Board believes that it did not follow proper excavation techniques in exposing the pipelines to be crossed, although the information regarding the crossings which should have been supplied by Peace Pipe or Dome was incomplete.

The Board notes that the Pipeline Act and Regulations have been recently amended to ensure better prevention of damage to pipelines during construction activities. For the legislation to be effective, it is essential for operating companies and contractors to appreciate the reasons for the legislation and conduct their operations in a manner that will ensure that pipeline crossing activities cause no damage to existing lines.

DATED at Calgary, Alberta, this 3 day of August 1982.

V. E. Bohme, P.Eng.
Board Member

E. R. Brushett, P.Eng.
Acting Board Member

E. G. Fox, P.Eng.
Acting Board Member

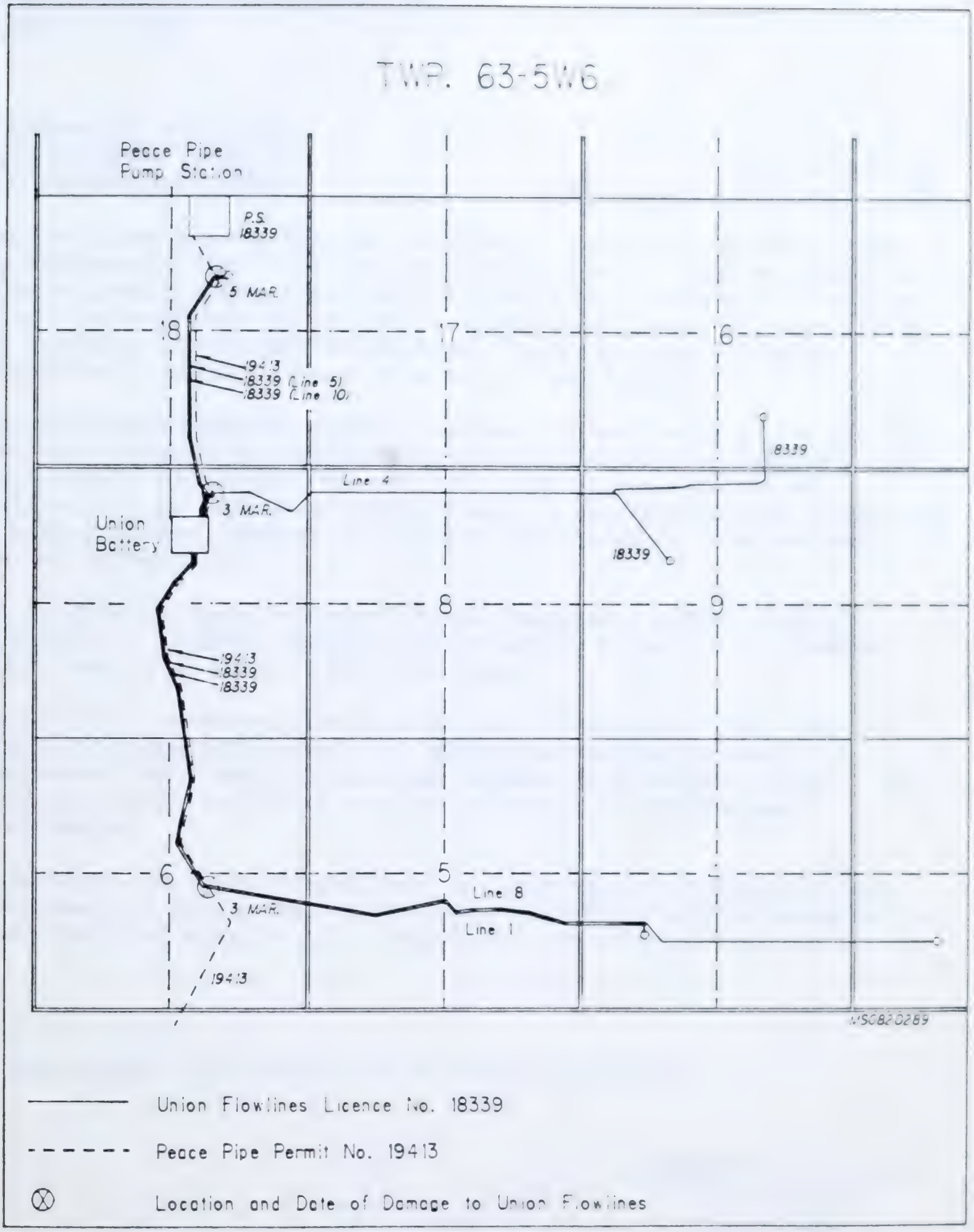

FIGURE TO INQUIRY REPORT - Proceeding 820289

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

FRACTIONATION FACILITIES
DOME PETROLEUM LIMITED
CHEVRON STANDARD LIMITED

Interim Decision
Applications 810916 and 811009

Dome Petroleum Limited applied, pursuant to section 38 of The Oil and Gas Conservation Act[1] (the Act), for approval of a scheme to expand its existing cavern storage facilities located in the north half of section 14 and the south half of section 23, township 55, range 22, west of the 4th meridian, in the Fort Saskatchewan Field, by constructing new facilities to extract propane from natural gas liquids.

Chevron Standard Limited applied, pursuant to section 38 of the Act for approval to expand its existing fractionation facilities located in the south half of section 14, township 55, range 22, west of the 4th meridian, in the Fort Saskatchewan Field, by constructing new facilities to extract ethane, propane, and butane from a mixture of ethane and heavier hydrocarbons.

The applications were considered by the Board at a public hearing in Calgary on 13 April 1982 with N. Berkowitz, P.Eng., C. J. Goodman, P.Eng., and G. A. Warne, P.Eng., sitting.

The Board has considered the applications; is satisfied that they are needed and technically sound; and agrees that neither proposed development would have a significant adverse environmental impact. The Board also notes that there were no objections to the proposed developments.

Accordingly, the Board hereby gives its approval in principle to both developments. The reasons for the Board's decision will be presented in a more detailed report which is expected to be released near the end of

---

1 Now section 26 of the Oil and Gas Conservation Act.

June 1982. The Board would at that time approve the applications subject to receipt of the necessary approval from the Minister of the Environment with respect to environmental matters.

ISSUED at Calgary, Alberta this 23rd day of April 1982.

ENERGY RESOURCES CONSERVATION BOARD

N. Berkowitz, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

G. A. Warne

G. A. Warne, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

FRACTIONATION FACILITIES
DOME PETROLEUM LIMITED — Interim Decision
CHEVRON STANDARD LIMITED — Applications 810916 and 811009

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Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

G. A. Warne

G. A. Warne, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

EMPRESS LIQUIDS PROCESSING JOINT VENTURE
REPROCESSING PLANT
EMPRESS AREA

Decision 82-1
Application 810898

1 APPLICATION AND HEARING

Empress Liquids Processing Joint Venture (Empress Liquids) applied, pursuant to section 38 of The Oil and Gas Conservation Act, for approval of a scheme for the extraction of natural gas liquids from sweet sales gas in a plant to be constructed in the southeast quarter of section 10, township 20, range 1, west of the 4th meridian. Empress Liquids is a joint venture of sixteen companies listed in Table 1-1. The application was the first part of a two-part application for approval to construct the plant; the second part, which would seek approval to operate the plant, is to be filed with this Board at a later date.

The proposed plant would be designed to process gas volumes equivalent to those authorized for removal from Alberta by ProGas Limited under gas removal Permit No. PG 79-1, plus shrinkage. The gas to be processed would be gathered and transported to the plant by NOVA, AN ALBERTA CORPORATION (NOVA) and Foothills Pipe Line (Foothills). The maximum design inlet capacity of the plant would be 9.86×10^6 cubic metres per day (m^3/d) and under normal operating conditions, some 9.02×10^6 m^3/d of gas would be processed for recovery of some 1081 m^3/d of ethane, as well as 525 m^3/d of propane and heavier liquids. Some 8.5×10^6 m^3/d of sales gas would be returned for sales to the NOVA and Foothills systems.

The application was considered by the Board at a public hearing in Calgary, Alberta on 21 December 1981 with N. Berkowitz, P.Eng., G. J. DeSorcy, P.Eng., and F. J. Mink, P.Eng., sitting.

TABLE 1-1

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Empress Liquids Processing Joint Venture* (Empress Liquids) D. G. Hart R. B. Horte	D. M. Wolcott, P.Eng. J. N. Dancey, P.Eng. J. E. Preece, P.Eng. D. L. Johnson
* comprised of Amoco Canada Petroleum Company Ltd. BP Exploration Canada Limited Canadian Superior Oil Ltd. Chevron Standard Limited D.M. Wolcott & Associates Ltd. Home Oil Company Limited Hudson's Bay Oil and Gas Company Limited ICG Resources Ltd. Kenaco Commercial Services Ltd. Luscar Ltd. Morgan Energy Inc. Norcen Energy Resources Limited Numac Oil & Gas Ltd. PanCanadian Petroleum Limited Shell Canada Resources Limited Texaco Canada Resources Ltd.	
Alberta Energy Company Ltd., Esso Chemical Canada, and Hudson's Bay Oil and Gas Company Limited J. Lowman	
Alberta Gas Ethylene Company Ltd. H. D. Williamson	
Alberta Natural Gas Company Ltd. J. R. Smith, Q.C.	
Amoco Canada Petroleum Company Ltd. F. B. Matthews, P.Eng.	

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations used in Report)	Witnesses
Canadian Superior Oil Ltd. B. Foster	
Dome Petroleum Limited W. M. Smith	
Home Oil Company Limited L. L. Conner	
ICG Resources Ltd. W. J. Smart, P.Eng.	
Norcen Energy Resources Limited H. H. Wind, P.Eng.	
NOVA, AN ALBERTA CORPORATION (NOVA) H. D. Williamson	
PanCanadian Petroleum Limited W. J. Hope-Ross, Q.C. E. H. Decter	
Petro-Canada Exploration (Petro-Canada) J. W. Gallagher	
Shell Canada Resources Limited L. Auger	
Texaco Canada Resources Ltd. W. Muscoby	
TransCanada PipeLines Limited (TransCanada) E. W. H. Mallabone	

BP Exploration Canada Limited and Mr. J. Hern filed interventions, but did not appear at the hearing.

2 INTERVENTIONS

Petro-Canada intervened to state that its existing reprocessing plant at Empress processes gas supplied by TransCanada, and that it expected the liquids contents of ProGas' and TransCanada's gas to differ from time to time. Since the gas would be commingled in the pipeline systems to the plants, the liquids content of each stream would be affected by the liquid content of the other. However, Petro-Canada could at this time offer no solution to the problem - if, indeed, it were to prove a problem.

Mr. J. Hern, who resides on the northeast quarter of section 3, township 20, range 1, west of the 4th meridian, filed an intervention, but was not represented at the hearing. He was concerned about potential air and noise pollution, increased traffic, and the siting of the proposed plant.

None of the other interveners presented evidence, but intervened only for the purposes of cross-examination and argument.

3 CONSIDERATION OF THE APPLICATION

The Board has considered the evidence respecting the need for a new reprocessing plant in the Empress area, the technical and conservation aspects of the proposed plant and its environmental impact, and finds that the plant would upgrade a provincial resource and be in the public interest. The Board notes that the applicant has met with the Regional Advisory Council and Mr. Hern, that it has published a notice respecting its proposed plant in the local newspaper, and that the concerns of local residents seem to have been resolved. No local residents appeared at the hearing. The Board also notes that the existing plant capacity at Empress would, by about 1983, likely be inadequate to recover liquids from all of the gas being removed from the province at that point. Additionally, the design of the proposed plant is new to Canada and appears very efficient. This is supported by evidence indicating that Alberta petrochemical producers find the cost of the ethane to be produced competitive with other sources and are interested in purchasing it.

With respect to the matter raised by Petro-Canada, the Board notes the applicant's suggestion that the average liquid content of the gas at Empress be used because the gas contracted by ProGas is an overall mix and because it is clearly impractical to gather and transport segregated streams to the plants. The Board recognizes the potential effect of the liquid content of one gas stream upon that of another; but this matter does not appear to raise any significant problems.

4 DECISION

The Board, being satisfied that Empress Liquids had demonstrated a need for the plant and shown that the proposed location, technical and conservation aspects, upgrading of resources, and environmental management are satisfactory, granted Empress Liquid's application at the conclusion of the hearing. Subject to receipt of the necessary approval from the Minister of the Environment with respect to environmental matters, the Board will issue the required approval.

DATED at Calgary, Alberta on 6 January 1982.

ENERGY RESOURCES CONSERVATION BOARD

N. Berkowitz, P.Eng.
Vice Chairman

G. J. DeSorcy, P.Eng.
Vice Chairman

F. J. Mink, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

AQUITAINE COMPANY OF CANADA LTD.
GULF CANADA RESOURCES INC.
NOVA, AN ALBERTA CORPORATION
PERMIT TO CONSTRUCT PIPELINES IN THE
STOLBERG - RICINUS AREAS

Decision Report 82-2
Applications 810629, 810630, 810631, and 810584

1 INTRODUCTION

1.1 The Applications

Four related applications were filed with the Energy Resources Conservation Board (Board) pursuant to The Pipeline Act, 1975[1]: two by Aquitaine Company of Canada Ltd. (Aquitaine)[2], one by Gulf Canada Resources Inc. (Gulf), and one by NOVA, An Alberta Corporation (NOVA). Aquitaine proposed two sections of pipeline to carry sour gas, and a line to transport fuel gas, located as shown in Figure 1. Gulf proposed a pipeline to carry sour gas, and NOVA proposed to add a loop line to its system, each located as shown in Figure 2.

Aquitaine applied for a permit to construct 23.0 kilometres (km) of 219.1 millimetre (mm) outside diameter (OD) pipeline from a central gathering site located in legal subdivision 7 of section 27, township 46, range 17, west of the 5th meridian, to a proposed field dehydration facility located in the Brown Creek field at Lsd 6-26-44-16 W5M. The application also included 44.7 km of 457.2 mm OD pipeline connecting the proposed Brown Creek field dehydration facility to the existing Stolberg gathering system at Lsd 2-3-41-14 W5M; the proposed system would transport sour natural gas with hydrogen sulphide (H_2S) concentrations of 93.2 mol/kmol from the Hanlan field, and 100.4 mol/kmol from the Brown Creek field to the Aquitaine Ram River plant. Aquitaine also applied for approval of an associated fuel gas pipeline parallel to the sour gas lines.

Gulf applied for a permit to construct 15.12 km of 219.1 mm OD pipeline to transport sour gas from Aquitaine's Ram River plant at Lsd 6-2-37-10 W5M to Gulf's Strachan plant at Lsd 11-35-37-9 W5M. The maximum H_2S content of the gas to be transported would be 138.2 mol/kmol.

NOVA applied for a permit to loop a portion of its existing Ricinus lateral, connecting the Aquitaine Ram River plant to the NOVA system. The loop would consist of 8.71 km of 406.4 OD pipe from Lsd 3-16-37-9 W5M to the Lsd 15-30-15-37-8 W5M. The gas to be transported would be sweet residue gas.

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1 Now renamed the Pipeline Act (Chapter P-8, RSA 1980)

2 Now known as Canterra Energy Ltd.

2 THE HEARING

The applications were considered at three consecutive public hearings on 29 October 1981 in Calgary, Alberta, with G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and N. Strom, P.Eng., sitting. Since the applications were somewhat dependent on applications to amend certain gas processing plant approvals, decisions respecting the subject pipeline applications were deferred until the processing plant matters were disposed of.

Those who appeared at the hearings are shown in the following table.

THOSE WHO APPEARED AT THE HEARINGS

Principals and Representatives (Abbreviations used in Report)	Witnesses
Aquitaine Company of Canada Ltd.2 (Aquitaine) F. M. Saville	J. Martin, P.Eng. P. Symborski, P.Eng. D. Johnson Dr. D. Leahey
Consolidation Coal Company D. K. Gay	B. Worbits
Gulf Canada Resources Inc. (Gulf) J. E. Nozick	K. B. Brown T. Finch R. B. Horne A. Avramenko J. French
D. Holt, J. R. Mott, H. Stelfox (landowners) D. Holt	D. Holt
Hudson's Bay Oil and Gas Company Limited (HBOG) A. G. Kruse	
Luscar Ltd. (Luscar) K. G. Crane	
NOVA, An Alberta Corporation (NOVA) D. Williamson	F. Barlage, P.Eng. V. B. Kromand, P.Eng. K. Exner Dr. J. B. Lee
Department of Environment R. Dyer	
Energy Resources Conservation Board staff D. Holgate G. Dunn, P.Eng. R. Allman, P.Eng. G. J. Vogt	

3 THE ISSUES

The Board considers the major issues of the applications to be:

- The need for the pipelines.
- The routing of the pipelines and landowner concerns.
- Technical design mattters.

4 THE NEED

4.1 Aquitaine (Applications 810629 and 810630)

Views of Aquitaine

Aquitaine's application described three alternatives considered by the company for processing gas from the South Hanlan and Brown Creek areas, including the applied-for pipelines to connect the areas to the Aquitaine Ram River plant. It supported its application by providing cost estimates for each possible case, and estimated the most economic solution was to transport the gas to the Ram River plant where sufficient capacity exists without requiring additional major capital expenditures for processing. The cost of this alternative would be some $30 million. Aquitaine considered the most expensive solution was to construct a new plant in the Brown Creek area. This option would also require railroad construction to move sulphur from the new location. The costs of this option were estimated to be $200 million, excluding the cost of the gathering system. Aquitaine emphasized that the cost of new gas processing facilities is substantially higher today than the costs associated with the original Ram River plant construction, and on this basis the company believed it highly preferable to use existing facilities.

The third processing alternative considered was to expand the capacity at the Gulf Robb-Hanlan plant which is currently under construction. The applicant's cost estimate for this solution was $120 million, including approximately $20 to $30 million for the gathering system.

Aquitaine stated it had discussed with HBOG the possibility of expanding the capacity of the proposed HBOG Brazeau plant to include volumes from the Brown Creek, Hanlan South and Brazeau areas. In its opinion and for reasons stated previously, the cost of processing would be lower by using existing capacity.

Views of the Interveners

Although the Board had received some written submissions, these generally did not deal with the need for the proposed Aquitaine pipelines. One company, Amoco Canada Petroleum Company Ltd., supported the applications and no interveners opposed the applications.

The representive of HBOG attempted, during final argument, to describe HBOG's proposed Brazeau plant as a location at which to process the South Hanlan and Brown Creek reserves, and to show the effect of this on the potential environmental impact of the proposed pipeline crossings of the Elk and Brazeau rivers. The Board ruled that such statements would constitute evidence rather than argument, and noted that HBOG had chosen not to present a witness or to call evidence. HBOG then declined further comment on its position.

Views of the Board

The Board is satisfied that sufficient gas reserves exist in the South Hanlan and Brown Creek areas to justify facilities to market the gas. The Board has assessed the alternatives discussed at the hearing and generally agrees with the applicant that the processing of such gas in the Ram River plant would be the least costly alternative. However, the economics of processing the gas is not the only matter which was considered when assessing the need for the proposed pipeline facilities. The Board has also had regard for the environmental and safety impacts of a lengthy sour gas pipeline, the sulphur recovery which would occur, the concept of emitting sulphur dioxide to the atmosphere at only one location as opposed to a number of different locations, the efficiency of the various alternatives with respect to energy conservation, land use impact, and the impact on other industrial operations or recreational facilities.

The Board concludes that any one of the alternatives would involve significant lengths of sour gas pipelines with little difference in terms of impact on the environment, landowners, industrial operations, recreational facilities, or energy efficiency considerations. These conclusions reflect the evidence presented at the hearing respecting these matters. The Board notes that little discussion took place concerning the proposed HBOG plant in the Brazeau area, and that HBOG declined to call evidence even though it appeared to be of the view that such a plan might be a better option.

Regarding the alternative of constructing a new gas plant in the area of the Robb-Hanlan gas field, the Board notes that use of the existing Ram River plant, which has a tail gas clean-up unit, would result in higher sulphur recovery; and also sees some advantage in one less emission point for sulphur dioxide.

4.2 Gulf (Application 810631)

Views of Gulf

Gulf stated that the applied-for pipeline was necessary to transport gas currently being processed at the Ram River plant to the Gulf Strachan plant for processing. Additionally, it pointed out that if Aquitaine Applications 810629 and 810630 dealt with in this report were approved,

additional reserves from Gulf wells at Stolberg and Brown Creek could be moved through the new line to Ram River, and thence to the Strachan plant for processing. Representatives for Gulf indicated that additional gas volumes were required at the Strachan plant to keep the raw-gas throughput of that facility at operationally efficient level.

Although Gulf indicated in its submission that Ricinus D-3 A unit gas was backing out Ricinus West gas to the Aquitaine Ram River plant, this statement was subsequently corrected in direct evidence during the hearing. It confirmed that capacity for the Ricinus West gas did exist at Ram River except when the plant was put on test by gas purchasers. Gulf said that, even though its gas was not currently being backed out of the Ram River plant, minimum processed quantities were not guaranteed by contract. Gulf also stated some misgivings about the capacity of sulphur handling facilities at the Ram River plant to accommodate the additional load that would occur if the Aquitaine applications were approved.

It indicated that the Strachan plant is currently operating at approximately 63 per cent of capacity, and that further reductions in throughput would result in a high recycle rate through the deep cut liquid extraction facilities as well as relatively low acid gas flow to the sulphur plant reactor beds. Based on a projected annual decline of approximately 10 per cent of capacity, Gulf believes that major turn-down modifications would be required within a few years. These could be deferred by moving additional gas to the Strachan plant for processing.

The applicant also pointed out other benefits could result from the construction of the proposed pipeline. In its view the continued operation of the deep cut liquid extraction facility at Strachan would maximize hydrocarbon liquids recovery from the gas produced and thus provide a greater benefit to the Province.

In Gulf's opinion, the maximum utilization of existing gas processing facilities would be in the public interest since it would allow continued gas production without the construction of new plant facilities. Finally, Gulf indicated that some years from now, when operation of the Strachan plant is no longer economic, the proposed pipeline could be reversed to transport Strachan volumes to the Ram River plant.

Views of the Interveners

Although no interveners presented evidence as to the need for the Gulf pipeline, two producers supported it as a means to transport their gas to the Gulf Strachan plant for processing.

Views of the Board

The Board has reviewed the evidence presented by Gulf and is of the opinion that there are certain advantages to the owners of the Strachan

plant, and to the Province, if the plant continues to operate at reasonably high throughputs. Also, since the Board has decided in favor of Aquitaine's application to process Brown Creek, Hanlan south and Brazeau reserves at the Ram River facility, the Board agrees that there could be some signficant capacity constraints at the Ram River plant. These constraints could occur both in the processing capacity and in sulphur handling facilities.

In summary, the Board agrees that Gulf has demonstrated a need for its proposed pipeline.

4.3 NOVA (Application 810584)

Views of NOVA

NOVA indicated that the capacity of the Ram River plant currently exceeds by 2.037 106 m^3/d the capacity of the Ricinus lateral, which moves gas from the plant to the NOVA eastern system (Edson-Clearwater) mainline. The shippers have requested NOVA to increase the capacity of this lateral.

NOVA pointed out that Aquitaine had increased the Ram River plant capacity in 1980, and stated that the total daily contract quantity (DCQ) requested was 10.156 x 106 m3/d. In response to questioning NOVA claimed that removal of Gulf gas from the Ram River plant did not alter the need for the Ricinus lateral loop. It was NOVA's position that the presently contracted maximum daily quantity (maximum day) of 1.25 times the DCQ is some 12.7 x 106 m3/d whereas the Gulf gas is only approximately 0.4 x 106 m^3/d.

In its application, NOVA provided a reserves summary for the fields presently being serviced through the Ram River processing facilities, including approximately 6100 x 106 m^3 of reserves in the Stolberg and Ricinus fields belonging to Gulf and its partners. However, as indicated earlier, NOVA contended that this did not affect the need for its proposed pipeline.

Views of the Interveners

Aquitaine, the operator of the Ram River plant, stated support for the NOVA application. No other interveners commented on this matter.

Views of the Board

In reviewing the need for the pipeline proposed by NOVA, the Board has kept in mind the other related pipeline applications currently before it. The Board notes that the reserve figures presented by NOVA do not include any reserves not already connected to the Ram River plant but do include

some reserves which would be processed by Gulf should its application be approved. Taking this into account, the Board is of the view that the rate of take required to make the proposed NOVA pipeline necessary is higher than normal, and in the Board's opinion is somewhat optimistic. However, the Board also recognizes that the "maximum day" requirements could approach plant capacity, in which case the proposed NOVA line would be needed. This need would be increased if the proposed Aquitaine line to move gas from the South Hanlan and Brown Creek areas is approved. To some extent then, the need for the Ricinus lateral proposed by NOVA is dependent on the disposition of the Aquitaine and Gulf pipeline applications. If these applications are approved, the Board is satisfied that justification would exist for the loop proposed by NOVA.

5 THE PIPELINE ROUTES

5.1 Aquitaine (Applications 810629 and 810630)

Views of Aquitaine

The applicant stated that the basic premise of its pipeline route selection was to find the shortest practical distance between the South Hanlan area, the Brown Creek and Stolberg dehydration facilities, and the Ram River plant, while at the same time staying within the constraints of current environmental and linear development guidelines. Wherever possible, existing seismic cut lines and roadways were incorporated into the proposed right of way. A geotechnical survey had been undertaken along the route, particularly to ensure safe river and stream crossings.

In considering alternative routings, Aquitaine found that between 70 and 80 per cent of the first 36 km of the preferred route could follow existing linear disturbances. For this reason no alternative routes had been considered for this portion of the line. From the Wawa Creek area south to the Stolberg tie-in, two routes were studied (see Figure 1). The first, east of Colt Creek, is the preferred choice of Aquitaine. It minimizes the creation of additional access to the area by using existing roads and cutlines, and involves six fewer intermittent stream crossings and a crossing of Colt Creek. The alternative route to the west is generally over rougher terrain, traverses 7 additional kilometres of critical wildlife area, and is somewhat more environmentally sensitive. According to Aquitaine, the alternative route has certain advantages of length (1 km shorter) and cost, but Aquitaine believes these are more than offset by the disadvantages identified.

Aquitaine indicated that it had discussions with the three principal coal leaseholders in the area, and foresaw no major problems. It was prepared to negotiate minor deviations along the route to accommodate coal lease holdings. Aquitaine believed it could minimize the sterilization of coal on the leases while still meeting the environmental objectives of route selection.

Aquitaine also confirmed that it would accept a permit condition imposed by the Board requiring the permittee to negotiate to try to reach agreement with the coal leaseholders respecting minor route adjustments and that, if agreement could not be reached, the matter would be referred back to the Board. Aquitaine also pointed out that the majority of the coal leases were to the west of its preferred route.

Views of the Interveners

The representative from Luscar stated concern about Aquitaine's alternative route impacting on Luscar's coal leases and coal reserves, and sought assurance from Aquitaine that the latter would be willing to negotiate route changes to minimize such impacts if this proved necessary.

Views of the Board

The Board believes that the applicant's preferred route is environmentally sound, and takes advantage of existing linear disturbances to minimize new rights of way. The Board is also of the opinion that, on balance, the preferred route to the east has significant advantages over the western alternative and, notwithstanding the additional length and cost, believes that the route to the east is the better of the two.

The Board notes the commitment made by Aquitaine to negotiate route adjustments around coal leases should this prove necessary, and the Board would intend to make this a condition of any permit issued to Aquitaine.

5.2 Gulf (Application 810631)

Views of Gulf

Gulf stated that it had considered several route options, but chose the one that created the least environmental impact inasmuch as it followed existing pipeline and powerline rights of way. Although the proposed route would involve five stream crossings, including Vetch Creek which had a construction timing restriction imposed by Fish and Wildlife, Gulf affirmed that it would abide by any guidelines set down by the appropriate government agencies involved. Under questioning, Gulf acknowledged that a number of marshy areas exist along the proposed route, and stated that any slope instability problems and other geotechnical matters would be dealt with at the time of construction.

On the matter of right of way easements and working space, Gulf stated that it intended to obtain the use of existing rights of way held by other operators for the placement of the majority of its line, and that if extra working space was required, it would be negotiated with the

respective landowners. For rights of way where Gulf presently has a line, Gulf's policy is to negotiate a separate agreement with the landowner, notwithstanding that it might already have the legal right to construct a second pipeline within the right of way.

Views of the Interveners

Mr. Holt, representing three private landowners affected by Gulf's proposed route, contended that the property in their area had potential for resource development and recreational use by virtue of government designation. He further stated that their lands would be devalued by the presence of a second sour gas pipeline. Asked to elaborate, Mr. Holt suggested that additional land restrictions would come into being because of the difference between the existing Level 3 and the proposed Level 4 sour gas pipelines. Because of this, he asked the Board to withhold the granting of a permit until negotiations could take place between Gulf and the landowners to compensate them for devaluation of their property. Mr. Holt recognized that the Board has no jurisdiction over matters of compensation, but had not realized until then that he had recourse through another agency.

Views of the Board

The Board is satisfied from the evidence presented that the proposed route would cause minimum disruption to the environment because of following existing rights of way. The absence of objections from the Crown or any of the companies owning rights of way where Gulf would place its line indicates to the Board that a route obtained in existing rights of way is a viable proposal. The Board notes, however, that the applicant has not negotiated with Dome regarding the possible sharing of Dome's right of way.

In the case of the private landowners along the route, the Board notes that a sour gas pipeline already exists across much of the property in question. The Board recognizes, however, that compensation for any apparent devaluation of the landowners' property by a second line can be negotiated with the applicant or, in the absence of agreement, recourse may be sought through the Surface Rights Board. Although the Board could withhold the permit until such time as the applicant has sucessfully negotiated with all landowners, it does not believe that this would fulfill the requirement of being economic and orderly and therefore would not be in the public interest.

The Board has reviewed the pipeline design and believes that it would be feasible and useful to maintain the sour gas release level of the new pipeline at the same level as the existing sour pipeline (Level 3). Accordingly, the Board is prepared to accept the design subject to this modification by Gulf.

5.3 NOVA (Application 810584)

Views of NOVA

NOVA stated that the proposed loop would parallel its existing Ricinus lateral generally within the present right of way, that no alternative route had been investigated, and very little extra working space would be required. Of 13 parcels of land involved, 1 was freehold, 2 were Crown and occupied, and 11 were Crown and vacant. NOVA had sucessfully negotiated consent for the freehold, Crown and occupied parcels, and right of entry on the remaining parcels had been obtained from Energy and Natural Resources.

NOVA had identified two environmental issues, namely the extra width of right of way needed, and concern for the integrity of the Vetch Creek crossing. On the former, NOVA stated that very little extra right of way would be involved and therefore environmental impact would be kept to a minimum. On the latter, the banks of Vetch Creek at the proposed crossing location had been altered significantly when the Ricinus lateral was constructed and bank reconstruction had been necessary. Similar work would be undertaken for the new loop line if necessary. In addition, winter construction of the crossing would prevent interference with fish incubation since there would be a minimum of fine sediment released.

Views of the Board

The Board believes that construction of the loop line within an existing NOVA right of way would result in a minimum of environmental impact, and that an alternative route would not be practical. From the evidence presented, all landowner matters have been satisfactorily negotiated, and the Board does not see any outstanding issues concerning the proposed route.

6 TECHNICAL MATTERS

6.1 Aquitaine (Applications 810629 and 810630)

Aquitaine indicated that there is available capacity in the existing Stolberg pipeline to transport gas from the South Hanlan area for processing in the Ram River plant. Generally, Aquitaine would size the proposed pipeline to accommodate potential future reserves in the area. In order to accommodate higher volumes in the existing Stolberg pipeline, some looping of that line would be necessary to bring its capacity to the level of the section applied for.

The applicant indicated that the following measures would be part of its design, operating, and maintenance program for the proposed pipelines:

(a) The proposed pipelines and all valve, flanges and fittings have been designed to meet or exceed minimum sour gas service criteria in accordance with Canadian Standard Association Standard Z184-M1979, NACE Standard MR-01-75 1980 Revision, and pertinent Board policies and directives.

(b) The effects of worst-case line ruptures and yearly individual risks were analysed to determine the location of block valves so as to reduce yearly individual risks to less than 10-6, a statistical level of risk generally considered acceptable by society. As a result, potential hydrogen sulphide release volumes will be reduced to a Level 3 classification from Level 4, as per Interim Directive 79-2[3], in the proximity of the Burner Sawmill and Shunda Creek campground.

The proposed block valves would be designed to automatically close within 5 to 20 seconds, upon detection of high or low line pressure.

(c) Pipeline operating modes would be continuously monitored at the Ram River plant control room, with a remote terminal unit at the Brown Creek dehydration site.

(d) Pressure drop sensors capable of detecting leaks would be established at the pipeline isolation valves, with ability to detect rapid or long declining pressure drops.

(e) An inhibitor program would be implemented to control internal corrosion, including corrosion coupons to gauge success.

(f) Aerial reconnaissance of the proposed lines would take place approximately once a month.

(g) A contingency plan would be in place in the event that a failure occurs.

6.2 Gulf (Application 810631)

Gulf indicated that the following measures would be part of its design, operating, and maintenance program for the proposed pipeline:

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3 Energy Resources Conservation Board. Minimum Distance Requirements Separating New Sour Gas Facilities From Residential and Other Developments. ERCB Report, 79-2. Calgary, Alberta. Since re-issued as Interim Directive 81-3.

(a) The proposed pipeline and all valves, flanges and fittings have been designed to meet or exceed minimum sour gas service criteria in accordance with Canadian Standard Association Standard Z184-M1979, NACE Standard MR-01-75 1980 Revision, and pertinent Board policies and directives.

(b) Setback requirements, as outlined in the Board's Interim Directive 79-2[3], would be analysed and, all residents within the setbacks would be contacted.

(c) Isolating valves would be placed between the Strachan and Ram River gas plants, with fail-safe actuators set to close on detection of high or low pressure.

(d) All equipment would be checked daily and all isolating valves would be tested on a regular basis.

(e) An inhibitor program would be implemented to control internal corrosion, along with a regular inspection program to monitor its success.

(f) The pipe would be externally coated and cathodic protection would be installed to prevent external corrosion.

(g) The Strachan gas plant emergency procedures manual would be modified to include the proposed pipeline.

Views of the Board

The Board has reviewed the overall pipeline design and procedures proposed by Aquitaine, Gulf, and NOVA, and is satisfied that they comply with the requirements of the Pipeline Act. Respecting the Aquitaine and Gulf applications, each aspect of the design for sour gas service has been reviewed with respect to the NACE Standard MR-01-75 1980 Revision, as well as other regulations prescribed under the Pipeline Act.

On the matter of risk, the Board has reviewed the Aquitaine and Gulf applications giving particular attention to the potential sour gas release level of the facilities, the topography, and spacing to known and possible areas of development. As indicated in section 5.2, the Board believes that it would be beneficial to maintain the proposed Gulf pipeline at the same release level (Level 3) as the existing adjacent pipeline. The Board believes that this would not impose a significant penalty on Gulf and yet this measure would allow any potential developments to proceed to current allowable levels of development. This could be accomplished by the addition of one properly located emergency shut down valve in the pipeline.

With respect to the proposed Aquitaine sour gas pipeline, the Board has reviewed this application in a similar way. Again topography, release level of facilities and spacing to known and possible areas of development were considered. Although several sections of the proposed sour gas pipeline are release level 4 (Level 4) facilities, the Board notes that there are no permanent human habitations in these areas and in fact there is no easy means of access to the large areas of lands traversed by those sections of the pipeline. The Board notes that the Level 4 segment, with a potential release volume of 9119 m^3, nearest to the Burner Sawmill is nearly 2 kilometres from that site. The nearest high level release segment, with a potential release to 25,450 m^3, is approximately 5.6 kilometres from the sawmill site and approximately 7.2 kilometres from the campsite on Shunda Creek. The Board also notes that the release levels for those segments nearest the sawmill and campground have been limited so as to comply with the Board's interim directive 79-2[3]. For these reasons, and bearing in mind that there were no objections to the proposed line, the Board concludes that the pipeline release levels are acceptable and would not present unduly high risks to those people who might visit or work in the general area of the pipeline.

The Board notes that Aquitaine and Gulf have provided sufficient detail concerning their planned operating and maintenance procedures to indicate the systems will be appropriately monitored and maintained. The Board is therefore satisfied that adequate design and safety standards are being applied.

The Board is also satisfied that the pipelines are sized appropriately and that other necessary technical and safety considerations have been addressed.

7 DECISION

The Board is satisfied that the pipelines proposed by Aquitaine, Gulf and NOVA are all in the public interest and should be approved. They are environmentally and technically acceptable (subject to the conditions applied to the Gulf and Aquitaine applications) and are required in the interests of economic and orderly development of pipelines in Alberta.

Accordingly, upon receipt of approval of the Minister of Environment, the Board will issue permits for the applied-for pipelines which are the subject of this report.

ISSUED at Calgary, Alberta, on 21 May 1982.

ENERGY RESOUCRES CONSERVATION BOARD

G.J. DeSorcy

G.J. DeSorcy, P.Eng.
Vice Chairman

C. J. Goodman

C.J. Goodman, P.Eng.
Board Member

N. Strom

N. Strom, P.Eng.
Board Member

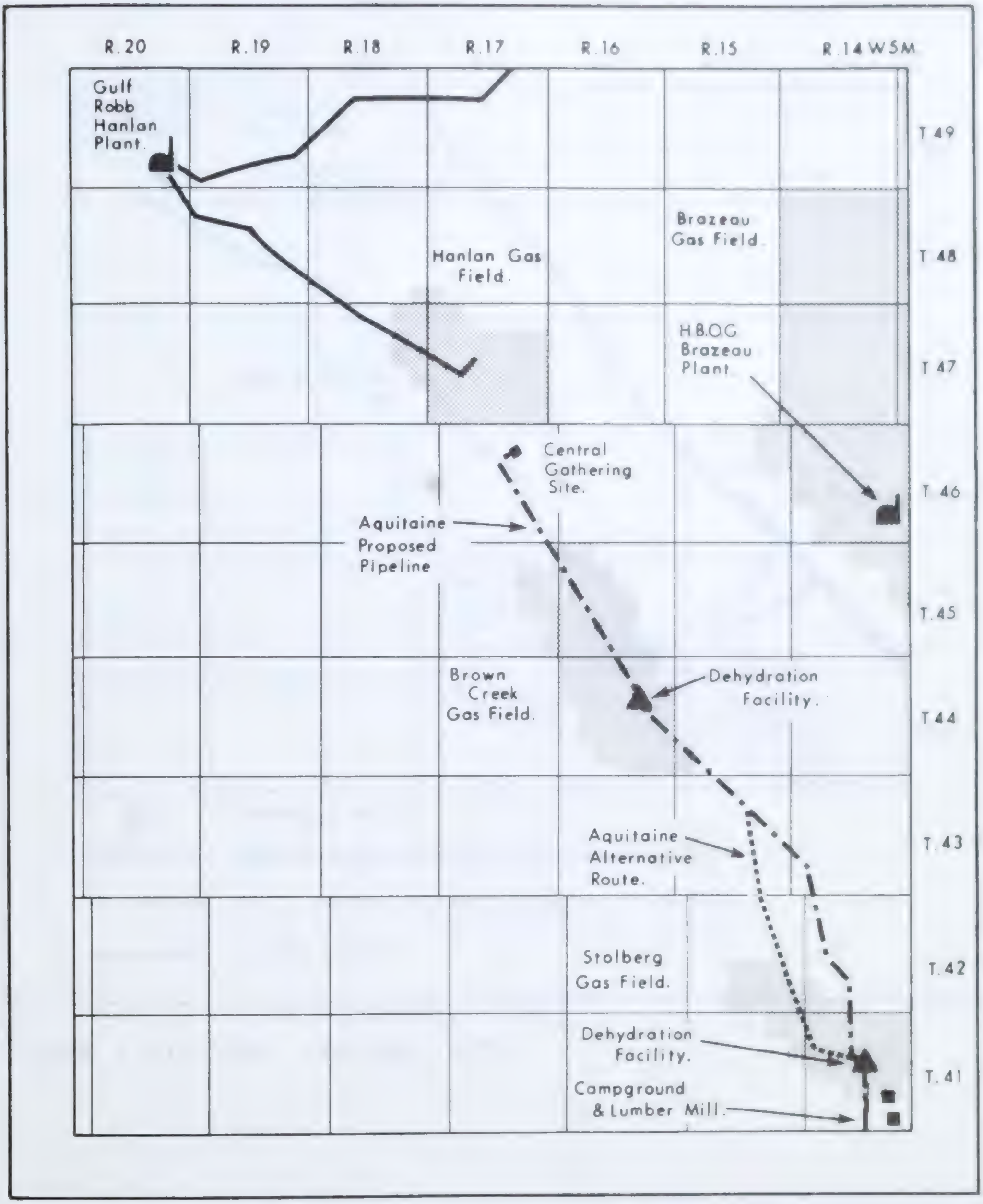


FIGURE 1 SOUTH HANLAN - STOLBERG AREA.

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

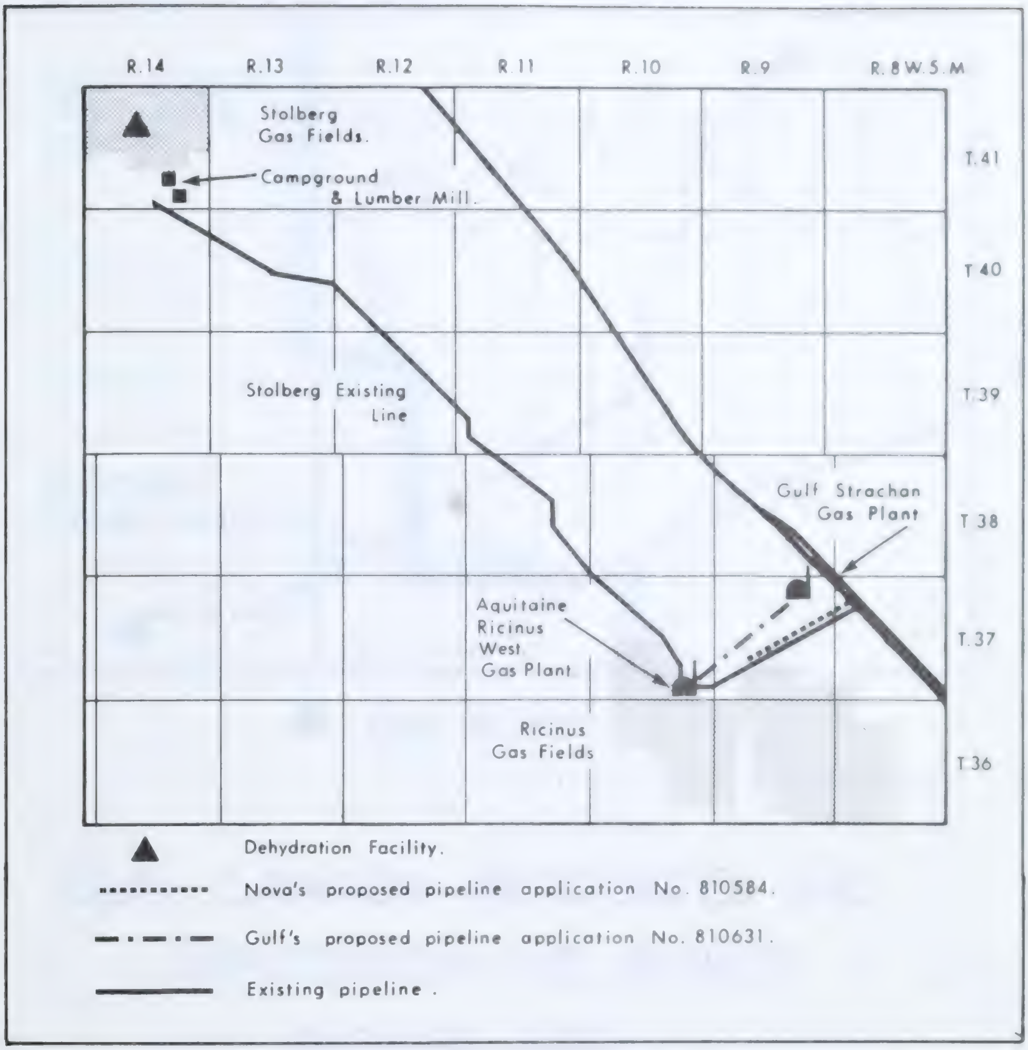
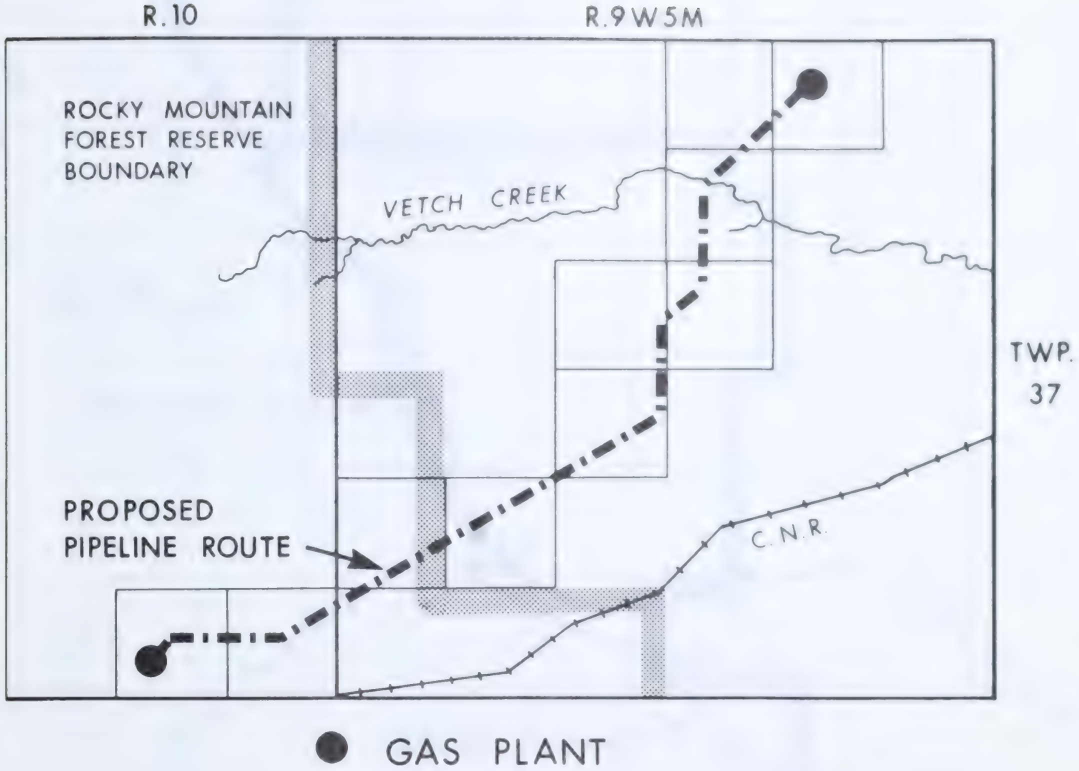
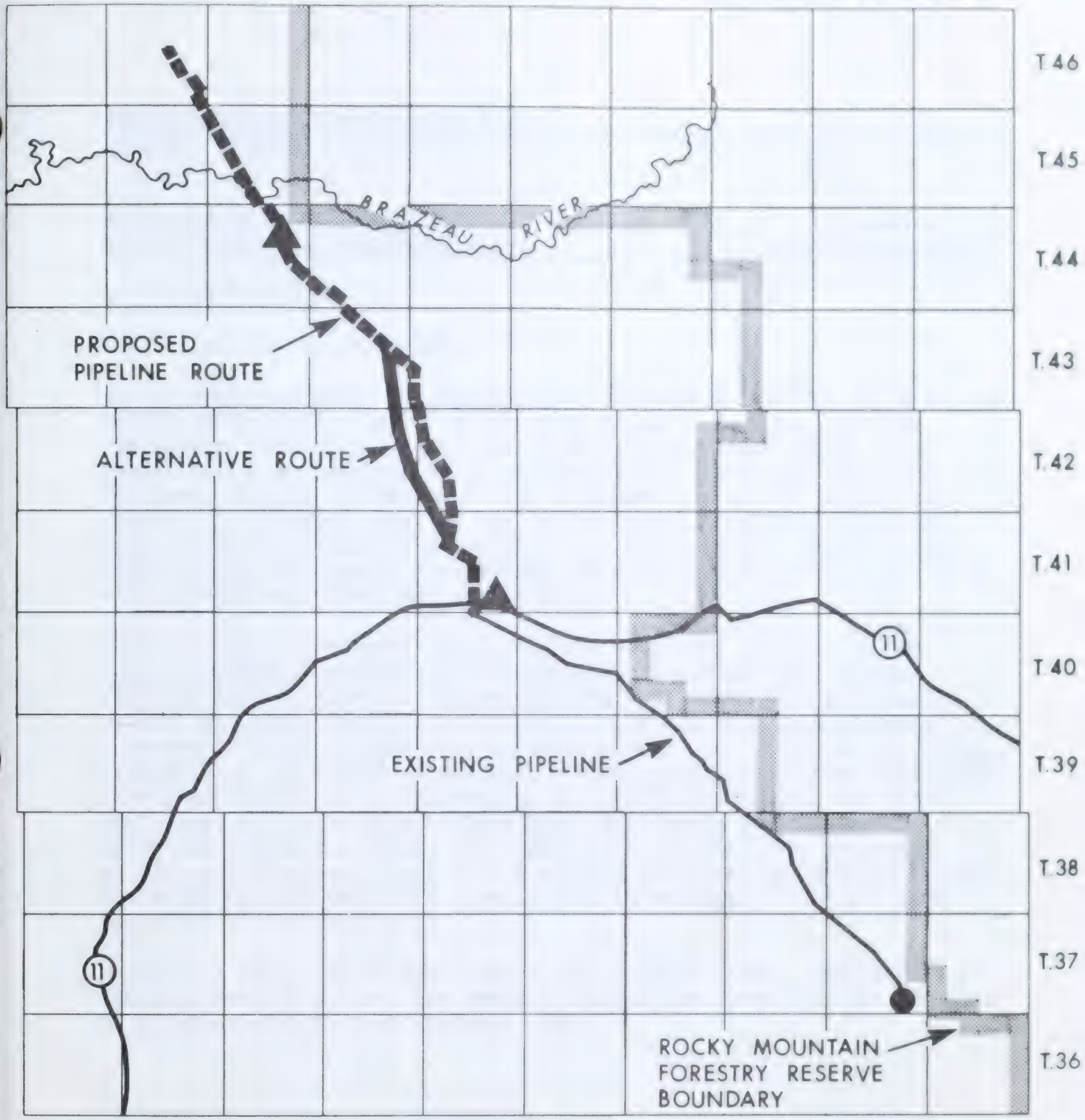


FIGURE 2 STOLBERG -RICINUS AREA.

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA CANADA



GULF CANADA RESOURCES INC.
APPLICATION NO. 810631
RICINUS AREA



▲ PROPOSED DEHYDRATION FACILITY

● GAS PLANT

AQUITAINE COMPANY OF CANADA LTD.
APPLICATION NO.'S 810629 AND 810630
SOUTH HANLAN - STOLBERG AREA

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

SHELL CANADA RESOURCES LIMITED
JUMPING POUND GAS PROCESSING PLANT

Decision 82-3
Application 810092

1 INTRODUCTION

1.1 Application and Hearing

Shell Canada Resources Limited applied, pursuant to section 38 of The Oil and Gas Conservation Act[1], for approval to add a deep-cut unit for hydrocarbon liquid extraction and to modernize sulphur recovery facilities at its Jumping Pound gas processing plant located in the northwest quarter of section 13 and southwest quarter of section 24, township 25, range 5, west of the 5th meridian. The details of the application are discussed in Section 2 of this report. The attached figure shows the Jumping Pound plant and other plants in the area along with certain major features of the area.

The application, and additional evidence submitted by Shell at the Board's request respecting the feasibility of 100 per cent sulphur recovery and the injection of waste gases, was considered at a public hearing in Calgary on 5 to 9 October, 2 to 5 November, and 23 and 27 November 1981 with V. Millard, N. Strom, P.Eng., and R. G. Evans, P.Eng., sitting. In its notice of hearing, the Board indicated that immediately after the conclusion of the hearing of Application 810092, the Board would hear an application by Esso Resources Canada Limited for its Quirk Creek gas processing plant, and applications by Shell for proposed pipelines and related facilities involving the Moose and Whiskey Fields. These latter applications are dealt with in Decision 82-12[2] and ERCB Report 82-E[3], respectively.

Appendix A is a list of those appearing at the hearing. Esso and Canadian Western Natural Gas Company Limited intervened for the purposes of cross-examination and argument only.

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1 Now section 26 of the Oil and Gas Conservation Act, (RSA 1980, c. O-5).

2 Energy Resources Conservation Board, 1982. Esso Resources Canada Limited Quirk Creek Gas Processing Plant. ERCB Decision 82-12. Calgary, Alberta.

3 Energy Resources Conservation Board, 1982. Shell Proposed Moose and Whiskey Pipelines and Related Facilities - Kananaskis Area. ERCB Report 82-E. Calgary, Alberta.

The other interveners, Z. Hanen and Rumsey Ranches, A. Russell and the Canadian Wildlife Federation, and R. E. Wolf, were concerned primarily about the impact on air and water quality, soil, and human and animal health, owing to emissions from the plant including sulphur dioxide (SO_2), hydrogen sulphide (H_2S), hydrocarbons, and waste water, and the potential for emission of several substances which they referred to as "trace poisons and carcinogens". The interveners were also concerned about safety in the operation of the field facilities and the plant. The interventions are discussed in Section 3 of this report.

1.2 Background

The Jumping Pound gas plant commenced operations in 1951 for the processing of sour gas from the Jumping Pound Field. The processing capacity of the plant was 1.409×10^6 cubic metres per day (m^3/d) of sour raw gas inlet with a sulphur recovery capability of about 85 per cent. In 1961, wells from the Sarcee Field were tied into the plant but no changes occurred in the plant process at that time. By about 1968, wells in the Jumping Pound West Field were tied in and the plant was expanded to a capacity of 6.982×10^6 m^3/d with a sulphur recovery level of about 93.5 per cent. The raw gas inlet capacity of the plant has been increased over the years to the current capacity of 7.128×10^6 m^3/d. Similarly, sulphur recovery facilities at the plant have been expanded to handle added production. Presently, there are three sulphur recovery units in operation at the plant, Units 2, 3, and 4 which have inlet sulphur capacities of 81.3, 228.6, and 228.6 tonnes per day (t/d), respectively. Each has a recovery efficiency of about 95.8 per cent.

The minimum quarterly sulphur recovery level required in accordance with the plant approval has been 95.0 per cent since 1974. Although substantial recovery of propane, butanes, and pentanes plus has always been achieved at the plant, the proposed new facilities would permit increased recovery efficiency of these components and as well would allow recovery of ethane which presently is not recovered but is part of the sales gas stream.

2 APPLICATION IN DETAIL

Shell proposed to shut down its existing propane and butanes recovery unit and to install a deep-cut or turbo-expander unit which would result in increased hydrocarbon liquid recovery, including ethane, which would not otherwise be recovered. Shell requested amendments to Approval 2926 for the plant to increase the maximum permitted raw gas inlet rate from 7.128 to 7.262×10^6 m^3/d, for the recovery of 5.635×10^6 m^3 of sales gas, 445 m^3 of ethane, 164 m^3 of propane, 128 m^3 of butanes, 481 m^3 of pentanes plus, and 566 tonnes (t) of sulphur.

The increase in raw gas inlet rate would be required to compensate for the additional gas shrinkage resulting from the extraction of additional liquids, and would be needed to enable Shell to continue to meet sales gas commitments.

Shell proposed to install a new sulphur recovery unit (Unit 5) at the plant to handle the increase in sulphur inlet which would result from a combination of increased raw gas inlet rate and a slightly greater sulphur fraction in the raw gas inlet stream. Unit 5 would replace the existing, less efficient Unit 2 and a portion of the capacity of Units 3 and 4. Shell therefore applied to increase the required minimum quarterly sulphur recovery efficiency from 95.0 to 96.0 per cent and to decrease the maximum permitted SO_2 emission rate from 53.8 to 47.2 t/d. The SO_2 would be emitted to the atmosphere through the existing 102-metre (m) high incinerator stack.

Shell planned to continue using Units 3 and 4 to recover 369.8 t/d of sulphur from 386 t/d inlet at 95.8 per cent efficiency and to operate Unit 5 to recover 195.7 t/d from 203 t/d inlet at 96.4 per cent efficiency, resulting in an overall minimum recovery of 96.0 per cent. Referring to IL 80-24[4], Shell stated that the required minimum efficiency for the plant should be based on the capacity and efficiency of Units 3 and 4, and with respect to Unit 5, assigned 152 t/d of inlet sulphur at an efficiency of 95.8 per cent (the efficiency of Unit 2) and 51 t/d of inlet sulphur at an efficiency of 97.8 per cent (the efficiency required for a new plant at 589 t/d inlet by IL 80-24). Shell stated that, having regard for the contractor's guarantee of a maximum of 97.0 per cent recovery for Unit 5, it would attempt to maintain an overall quarterly efficiency of 96.2 per cent with a minimum of 96.0 per cent.

Shell stated that, assuming the contractor's process design efficiency of 97.0 per cent for Unit 5 with fresh catalyst, and assuming an average recovery of 96.2 per cent for Units 3 and 4, the overall recovery for the plant could be as high as 96.5 per cent. Shell stated that, while 96.5 per cent recovery was unlikely to be achieved year in and year out, it was prepared to use its best efforts to achieve this level on a quarterly-average basis. It stated that, if this level could not be achieved, it would apply to the Board for approval of a lower level until the peak inlet sulphur rate drops low enough to allow the guidelines to be met.

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4 Energy Resources Conservation Board, 1980. Sulphur Recovery Guidelines Gas Processing Operations. ERCB Informational Letter IL 80-24. Calgary, Alberta.

Shell stated that it would clearly not be economic to proceed as applied for if a sulphur recovery level of 97.8 per cent were imposed, because of the need to add a tail gas clean-up unit.

Pursuant to a requirement of the Board, Shell submitted reports respecting the technical feasibility and costs of:

- recovering essentially all of the sulphur contained in the gas, and

- injecting acid gas or tail gas into deep underground formations.

Shell stated that tail gas clean-up at the plant to reduce SO_2 emissions could not be economically justified. Shell further contended that tail gas clean-up was not warranted on environmental considerations recognizing that the currently-approved SO_2 emission rate had not resulted in any detectable environmental damage or other adverse effects over its 30-year operating history, and also recognizing that the modernized plant would reduce SO_2 emissions. Shell estimated that a Shell Claus Off Gas Treating (SCOT) unit would cost $65 million to install and would recover only an additional 23 t/d of sulphur from the 589 t/d inlet. Shell stated that tail gas clean-up would be wasteful of fuel and other natural resources and could not be constructed within the present plant complex owing to space limitations at and around the plant site.

On the feasibility of the injection of acid gas from the Jumping Pound plant into an underground formation, Shell's view was that it is not technically feasible as the metallurgical technology required to handle the corrosive gas mixture at high pressures is not proven. In addition, the requirement to shut down the sulphur plants would seriously affect the plant steam balance, and therefore require major plant modifications. Shell stated that, while the problems associated with injection of tail gas from the sulphur plants are potentially solvable, such a scheme would not be economically feasible, as would a scheme involving the injection of incinerator effluent. Shell's estimates of the costs were $118, $166, and $206 million for acid gas, tail gas, and incinerated tail gas injection, respectively.

3 INTERVENTIONS

As indicated in Section 1.1, the interveners were primarily concerned about the impact of emissions from the plant and safety of operation of the field facilities and plant.

With respect to the emission of SO_2, they stated that technology was available for tail gas clean-up which would result in the recovery of essentially all of the sulphur in the raw gas and allow essentially zero SO_2 emissions. Removal of carbon dioxide (CO_2) from the acid gas would have the benefit of increasing the H_2S to CO_2 ratio of that stream, thus improving sulphur recovery efficiency. In addition, they contended that the CO_2 in the acid gas stream could be extracted and used in enhanced oil recovery schemes. They stated that the added revenue from incremental oil recovery would help defray the cost of tail gas clean-up and, as well, recoverable oil reserves of the province would be increased. It was contended that, by using CO_2 from the acid gas from all sour gas processing plants in the province for enhanced oil recovery, Alberta's oil reserves could be increased by some 4.5 billion barrels.

The interveners raised the possibility of processing gas from the Moose Field at the Jumping Pound plant with a subsequent realignment of gas reserves among a number of plants west of Calgary. These Moose and Whiskey reserves are the subject of the Esso Quirk Creek plant application and the Shell pipeline applications referred to in Section 1.1.

The interveners provided witnesses to speak to such matters as tail gas clean-up costs, the feasibility of injecting acid gases in deep formations for disposal or enhanced oil recovery, acid rain, the potential for the formation and emission of "trace poisons and carcinogens", the suggestion of a relationship between SO_2 emissions and white muscle disease in animals, and corrosion effects of SO_2 emissions.

In closing argument, counsel for Ms. Hanen stated that much of the evidence respecting emissions did not show a cause and effect relationship. He asked that Shell's application be approved but with the following conditions:

- the required minimum sulphur recovery level be 100 per cent or as much as is technically feasible,
- if the Board does not direct the recovery of essentially all of the sulphur, the minimum requirement be higher than the applied-for level,
- stack emissions and flaring be continuously monitored and reported on, and
- an annual report be required of the chemical composition of the well effluent, plant inlet gas stream, stack and other sources of emissions, including an analysis for trace poisons and carcinogens.

Mr. J. Labuda, appearing on behalf of Mr. Russell and the Canadian Wildlife Federation, stated that Shell's estimate of $65 million for the capital cost of tail gas clean-up facilities for the Jumping Pound plant was too high, and he estimated the cost to be not more than $22 million. In closing argument, counsel for Mr. Russell stated that Shell's application should be approved conditional upon the installation of a tail gas clean-up unit.

4 PRELIMINARY CONSIDERATIONS RESPECTING THE APPLICATION

Before turning to the definition of issues, the Board believes that it must address two preliminary matters which arose out of the evidence and closing argument at the hearing. These two matters are with respect firstly to the purposes and intent of some sections of the Board's legislation, and secondly the nature of the evidence and closing argument.

Purpose and Intent of Legislation

Counsel for Ms. Hanen, in closing argument, referred the Board to, inter alia, two sections of the Board's legislation - section 5(e)[5] of The Oil and Gas Conservation Act and section 2(d) of The Energy Resources Conservation Act[6], each being one of several "purposes provisions" of the respective Acts. Those sections read as follows:

> "5. The purposes of this Act are
>
> (e) to control pollution, above, at or below the surface in the drilling of wells and in operations for the production of oil, gas and crude bitumen and in other operations over which the Board has jurisdiction."
>
> "2. The purposes of this Act are
>
> (d) to control pollution and ensure environment conservation in the exploration for, processing, development and transportation of the energy resources and energy."

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5 Now section 4(f) of the Oil and Gas Conservation Act (RSA 1980, c. 0-5).

6 Now the Energy Resources Conservation Act (RSA 1980, c. E-11).

In so doing, he pointed out to the Board that one of the main purposes under both Acts is to "control pollution". He noted that in respect of both sections, there is no economic test to be applied and he went on to say that economics is not a consideration under the legislation as it relates to the question of pollution control. He suggested that it was the responsibility, jurisdiction, and duty of the Board to control pollution.

The Board believes that, in discharging its duties under the Energy Resources Conservation Act and the Oil and Gas Conservation Act, it must have regard for all the purposes of the respective Acts, insofar as they are relevant to the application before the Board and insofar as they are not inconsistent with each other. The Board takes note of the wording of section 4(c)[7] of the Oil and Gas Conservation Act which obligates the Board to provide for the economic, orderly, and efficient development in the public interest of the energy resources of Alberta. The Board is of the opinion that this subsection must be read together with section 4(f) of the Oil and Gas Conservation Act and section 2(d) of the Energy Resources Conservation Act, and that accordingly, the Board must, in looking at the purposes of the legislation together, have regard for the economics as they affect the application.

In regard to the submission of counsel for Hanen, that the Board has a duty to make certain that pollution is controlled, without regard to economics, to the least possible amount consistent with the best available technology from time to time, the Board takes notes that in section 4(f) of the Oil and Gas Conservation Act and in section 2(d) of the Energy Resources Conservation Act, the words "control pollution" are used, as may be contrasted to the words "prevent pollution". The Board considers the words "control pollution", as used by the Legislature of Alberta, to be significant. The Board believes that if the Legislature had intended the Board to prevent pollution, then it would have used such express words.

In summary, the Board concludes that the legislation directs the Board to control or limit pollution. The degree of limitation would be influenced by various considerations including economics. It follows that the "best practical technology" is one compatible with the legislation. However, in particular instances and when warranted, the test might well be "best available technology".

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7 Previously section 5(b.1) of The Oil and Gas Conservation Act (RSA 1970, c. 267).

The Board recognizes that, with respect to the current application, it must operate within the existing legislative scheme at the time of the hearing of an application. In addition, the Board will, where policies and guidelines for pollution control standards exist, have regard for those policies and guidelines, but in so doing, the Board will consider the appropriateness of such policies and guidelines in each case before it. In other words, the Board, in assessing each application on its own merits, and after considering all the evidence in that regard, will decide whether there is some specific reason (ie. economics, environmental impact, public interest) directly related to the situation which would warrant the application of more stringent or less stringent standards in that case.

Nature of the Evidence

Much of the evidence and closing argument presented by the interveners at the hearing was not directly related to the subject application, but dealt with broad and general matters such as the adequacy of current Alberta standards and policies for sour gas operations, the potential environmental impact of emissions from sour gas plants, the potential for emission from sour gas plants of certain substances termed by the interveners as "trace poisons and carcinogens", and other matters. The Board believes that it would be appropriate for it to assess the subject application on the basis of the evidence which is directly related to it and the existing standards and policies, and to present its views separately on the more general evidence not directly related to the specific application. Therefore, for the latter purpose, the Board will issue a separate general report on Alberta sour gas processing plant operations.[8]

5 ISSUES

The Board believes that, having regard for the nature of the evidence presented at the hearing, and for its decision to report separately on the general matters on sour gas operations, it should consider Shell's application on its own merits and in relation to the existing standards and policies. The Board does not intend that this approach would preclude the application of more stringent standards for the Jumping Pound plant if the Board's detailed review of the evidence showed that there was some specific reason to do so. Therefore, the Board believes that the issues raised with respect to the specific application are:

- hydrocarbon conservation,

- environmental impact,

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8 Energy Resources Conservation Board, 1982. Sour-Gas Processing in Alberta. ERCB Report 82-D. Calgary, Alberta.

- sulphur recovery, including the feasibility of 100 per cent sulphur recovery, and
- the viability of injection of acid gas or tail gas from the Jumping Pound plant to deep underground formations.

6 CONSIDERATION OF THE APPLICATION

6.1 Hydrocarbon Conservation

The Board notes that the addition of deep-cut facilities at the Jumping Pound plant would increase the recovery of natural gas liquids and in particular, ethane, which would otherwise remain in the sales gas stream and be used as fuel, would be recovered and its value considerably upgraded as a petrochemical feedstock. The Board is satisfied that such recovery and use of ethane as well as the increased recovery of propane, butanes, and pentanes plus represents significant conservation of Alberta's natural resources and is in the public interest.

With respect to sulphur recovery, the Board is satisfied from a purely resource conservation point of view that the increased level of recovery proposed by Shell from the current level of 95.0 to 96.0 per cent is satisfactory. The matter of sulphur recovery from an environmental impact point of view is included in Section 6.3 of this report.

6.2 Environmental Impact

On the matter of environmental impact from SO_2 emissions, the Board was not presented with any specific evidence to demonstrate that the operation of the Jumping Pound plant at the currently-approved rates for sulphur recovery and SO_2 emissions has resulted in any adverse environmental impact. Similarly, with respect to other environmental effects of the plant including aqueous emissions, hydrocarbons, odours, smoke, and noise, the Board notes the general absence of objections at the hearing by the public in the area of the plant and the dearth of evidence on any adverse environmental impact. Consequently, the Board is satisfied that adherence to the relevant requirements would result in environmentally-acceptable operations. The matter of sulphur recovery level is dealt with in detail in Section 6.3.

The Board notes that Shell proposes to replace the existing gas-driven refrigeration compressors with electrically-driven units which would, at least with regard to the local situation, eliminate that source of emission of oxides of nitrogen (NO_x).

With respect to Ms. Hanen's request that stack emissions and flaring be continuously monitored and reported on, the Board notes that this is already being met as Jumping Pound is included with those plants handling more than 50 t/d of sulphur which are required to provide equipment to continuously monitor SO_2 emissions. Sour gas plants are also required to submit monthly, a daily sulphur balance for the plant, showing the sulphur inlet to the plant and the sulphur leaving the plant as a product or as an emission. Flaring must also be measured and reported to the Board monthly. The conditions of plant approvals require flaring to be limited to 0.5 per cent of the plant's inlet volume, the reporting to the Board at the time of any flaring incident extending for more than 48 hours, and prior Board approval for any scheduled flaring.

Respecting Ms. Hanen's request that an annual report be required of the composition of certain streams, the Board intends to deal with this matter in its general report on sour gas operations. In connection with the general matter of the potential for emission of trace poisons, the Board intends to have detailed analyses conducted by an independent laboratory on incinerator stack gases at a sampling of Alberta plants, including the Jumping Pound plant, to determine the presence or absence of such material. The results of these analyses will be made available to the public.

6.3 Sulphur Recovery

IL 80-24 intentionally left non-specific the exact method of application of the sulphur recovery guidelines to existing plants and plant expansions or alterations. The approach taken by Shell was to apply the guidelines to the incremental increase in sulphur plant capacity, namely 51 t/d. However, instead of applying the currently-approved recovery efficiency of 95.0 per cent to the existing capacity (538 t/d) Shell applied the currently-achievable recovery rate, namely 95.8 per cent. By this method 566 t/d out of the maximum 589 t/d inlet rate capacity would be recovered, or 96.0 per cent. Had Shell used the approval rate of 95.0 per cent for the existing capacity, the recovery would have been 5 t/d less and the average required recovery efficiency would be 95.2 per cent.

Another interpretation would be to apply the guidelines to the capacity of the new sulphur unit - 203 t/d. Following the procedure outlined above, the recoveries utilizing the current efficiency of the existing units would be 568 t/d out of the total capacity of 589 t/d or 96.5 per cent. If the current approval rate of 95.0 per cent were adopted for the existing capacity, then the required recovery would be 566 t/d or 96.0 per cent.

A more extreme interpretation of the guidelines would be to conclude that the addition of a sulphur plant of some 200 t/d capacity is such a substantial change that the guidelines should apply to the complete

Jumping Pound facility. If this interpretation were adopted, then the required recovery rate would be 97.8 per cent or 576 t/d. The Board believes that this interpretation of the guidelines is not reasonable for the current situation.

Thus, application of the guidelines to the Jumping Pound case results in a calculated recovery efficiency requirement ranging from 95.2 per cent to 96.5 per cent or recoveries ranging from 561 t/d to 568 t/d. The applicant has indicated that a required recovery efficiency in excess of 96.2 per cent would require the installation of tail gas clean-up facilities. It appears to the Board, therefore, that the primary question relating to the recovery rate that should be established for the modified Jumping Pound plant reduces to whether or not tail gas clean-up facilities should be required, and not to esoteric manipulations of the guidelines.

In assessing whether tail gas clean-up facilities should be required of the Jumping Pound operation, the Board has had regard for the following:

(a) No additional sour gas reserves would be processed. The additional facilities would permit an accelerated depletion of the sour gas reservoirs but would not increase the total gas processed at the plant.

(b) The production rate would be greater than would otherwise be the case for the initial 6 years but would then be less.

(c) The new sulphur unit would permit a somewhat greater recovery. Shell had advised that the installation of the new sulphur plant with tail gas clean-up would not be economic to proceed with as applied for. If the new sulphur plant were not installed, actual SO_2 emissions would continue at their current level.

(d) There is neither evidence nor allegation of environmental damage or stress from the Jumping Pound plant and none of the substantial number of nearby residents has objected to the proposed plant changes.

Having regard for the above-noted factors, the Board concludes that tail gas clean-up facilities are not justified for the Jumping Pound plant at this stage in its operating life. It does, however, believe that the recovery efficiency should be set at the highest possible rate that can be achieved on a consistent basis by the combination of the old and new facilities. Shell has indicated that it is confident that it can meet a recovery efficiency of 96.0 per cent and expects that it would likely achieve 96.2 per cent. Under these circumstances the Board believes that it should establish a sulphur recovery efficiency of 96.2 per cent.

With respect to the matter of the feasibility of 100 per cent sulphur recovery, an issue raised by the Board prior to the hearing, the Board agrees with the applicant and others that approximately this level of recovery is technically feasible. However, having regard for its conclusion respecting "best practical technology" in Section 4, the Board believes that the guidelines embodied in IL 80-24 should apply and under those terms tail gas clean-up facilities are not warranted in the Jumping Pound case.

6.4 Viability of Injection of Acid Gas or Tail Gas From the Jumping Pound Plant to Deep Underground Formations

The Board generally agrees with Shell's evidence respecting the uncertain state of metallurgical technology required for the injection of acid or tail gas. It has not reviewed in detail the applicant's cost estimates of the three injection alternatives which range from $118 million to $206 million, but accepts them as being reasonable. It notes that each of these alternatives would be significantly more costly than the 100 per cent recovery alternative. Additionally, the injection of either acid gas or tail gas could introduce potential environmental problems that would be more serious than the emission of the SO_2 which would otherwise occur. Accordingly, the Board does not believe that the injection of acid or tail gas from the Jumping Pound plant as a disposal plan to avoid SO_2 emissions is desirable or a reasonable alternative.

The Board has also reviewed the interveners' contention that recovery of waste gas either untreated or as a selectively-recovered CO_2 stream, should be undertaken for subsequent enhanced oil recovery injection operations. While the Board agrees that the selective processing is technically feasible, there was no evidence that it would be economically practical in this case. Indeed, the evidence rather clearly showed that this kind of a program would be very costly, particularly having regard for the substantial distance between the Jumping Pound plant and any prospective oil reservoir. The Board is satisfied that at least under current circumstances the suggestion that Jumping Pound waste gas could be used for oil recovery enhancement is not practical.

In summary, the Board believes that, even putting aside the practical questions of suitable reservoir availability and metallurgical technology, an injection scheme for Jumping Pound waste gases is not warranted for environment protection reasons, and would not be economically viable.

7 DECISION

Having been satisfied with the technical, conservation, and environmental aspects of Shell's proposal, the Board is prepared to amend Approval 2926 as indicated in this report. Subject to the receipt of the required approval of the Minister of the Environment with respect to environmental matters, the Board will issue the required approval.

DATED at Calgary, Alberta on the 7th day of April, 1982.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

N. Strom, P.Eng.
Board Member

R. G. Evans, P.Eng.
Acting Board Member

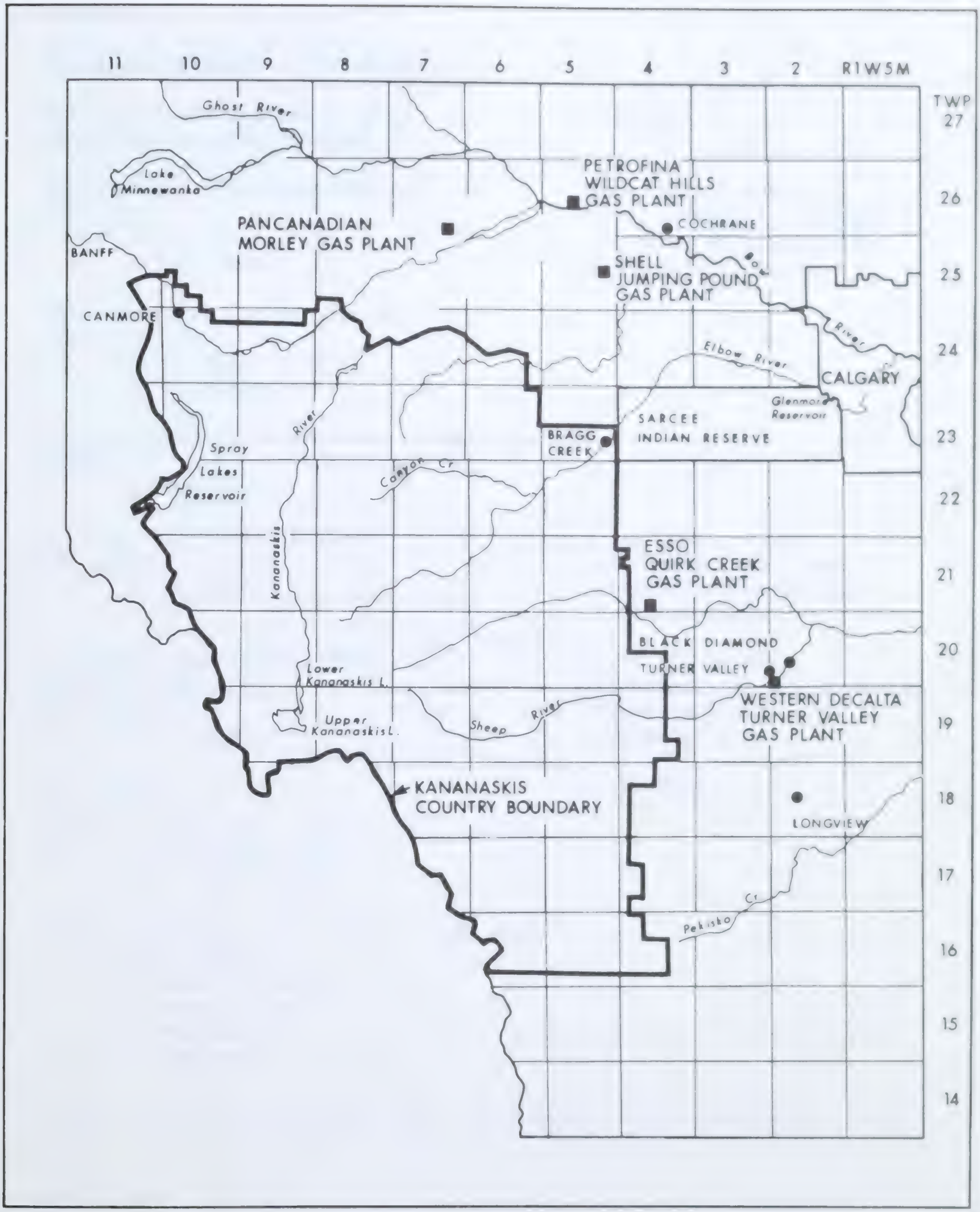


FIGURE TO DECISION 82-3. Shell Jumping Pound and other area gas plants

APPENDIX A

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbeviations used in Report)	Witnesses
Shell Canada Resources Limited (Shell) D. O. Sabey, Q.C. A.P.G. Walker	W. W. Evans, P.Eng. B. D. Weatherill, P.Eng. Dr. M. D. Winning, P.Eng. W. R. Grieef, P.Eng.
Esso Resources Canada Limited (Esso) D. G. Hart, Q.C. R. C. Pittman	
Canadian Western Natural Gas Company Limited (CWNG) J. DeGelder	
Z. Hanen and Rumsey Ranches (Ms. Hanen) J. D. Rooke	E. L. Jones, P.Eng. of Edward Lewis Jones & Associates Consulting Engineers Ltd.
A. Russell and the Canadian Wildlife Federation (Mr. Russell) P. J. Madden	Dr. C. F. Bentley of McAllister Environmental Services Ltd. J. Labuda, P.Eng.
R. E. Wolf	R. E. Wolf
Alberta Environment staff S. L. Dobko, P.Eng. C. S. Liu, P.Eng.	
Energy Resources Conservation Board staff K. F. Miller P. Raina, P.Eng. H. Knox, P.Eng. D. Mulrain L. Fillion	

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

NOVA, AN ALBERTA CORPORATION
PERMIT TO CONSTRUCT
THE GRAHAM LATERAL AND METER STATION
PRIMROSE AREA

Decision 82-04
Application 810576

1 INTRODUCTION

1.1 The Application

NOVA, An Alberta Corporation, applied pursuant to The Pipeline Act, 1975, for a permit to construct facilities to transport natural gas as follows:

Graham to Chard Jct
Lsd 11-19-80-4 W4M to 12-14-79-5 W4M
13.6 km x 219.1 mm O.D.,

Chard to Chard Jct
Lsd 14-32-79-5 W4M to 5-21-79-5 W4M
8.1 km x 168.3 mm O.D.,

Chard Jct to Kirby North
Lsd 12-14-79-5 W4M to 11-8-74-5 W4M
52.5 km x 219.1 mm O.D.,

Kirby North to Kirby North Jct loop,
Lsd 11-8-74-5 W4M to 6-29-73-5 W4M,
5.6 km x 219.1 mm O.D.,

and meter stations at

Graham, Lsd 11-19-80-4 W4M
Chard, Lsd 14-32-79-5 W4M

The above-mentioned facilities were requested by Pan-Alberta Gas Ltd. and TransCanada PipeLines Ltd., to transport new volumes of natural gas from the Graham and Chard areas to the Kirby area. A number of producers identified in Table 1 are, or will be, constructing gas plants in the area. The application also described an alternative route (Alternative 2), which would tie into Simmons Pipelines Ltd.'s Leismer lateral (see Figure 1). This alternative was not applied for by the applicant but was strongly supported by Simmons.

1.2 The Hearing

The application was considered at a public hearing on 18 November 1981 in Calgary, Alberta, with G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and F. Trofanenko (Public Utilities Board), sitting. See Table 1.

The following provided a written submission but did not appear at the hearing: Petrobolt Resources Ltd., and Touche, Thomson & Yeomen Exploration.

2 PRINCIPAL ISSUES

The Energy Resources Conservation Board considers the principal issues of this application to be:

- o reserves and deliverability
- o technical design
- o economic considerations
- o environmental considerations
- o orderly development
- o timing and impact on industry

3 RESERVES AND DELIVERABILITY

3.1 Views of the Applicant

During 1980, NOVA filed with the Board extensive reserves and deliverability studies relating to the Primrose area. This information was cited by NOVA as the basis for its application, and excerpts from it were included in the application. NOVA stated that the future reserves (trend gas) used in making the deliverability forecast was less than 10 per cent of the total reserves estimate provided.

Information supplied by NOVA indicates a possible total deliverability of 2.048 10^6 m^3/d (compared with 5th year pipeline design flow 1.200 10^6 m^3/d). The total estimated reserves for the Graham and Chard areas were placed at 15 000 x 10^6 m^3.

3.2 Views of the Interveners

Although several producers supported the pipeline proposal, none of those who appeared presented any evidence regarding reserves.

3.3 Views of the Board

The Board has reviewed the evidence presented regarding reserves and generally agrees with the figures presented. The Board believes that

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principal and Representatives (Abbreviations used in Report)	Witnesses
NOVA, An Alberta Corporation (NOVA) H. D. Williamson	V. B. Kromand, P.Eng. F. Barlage, P.Eng. C. P. Mason R. G. Marshall, P.Eng. R. W. Smidt Dr. J. B. Lee, P.Eng. L. Mattar, P.Eng.
Canadian Occidental Petroleum Ltd. (Occidental) D. W. Parsons	
Pan-Alberta Gas Ltd. (Pan-Alberta) K. F. Keeler	L. H. Larson, P.Geol. D. G. Snyder, P.Eng.
Paramount Resources Ltd. (Paramount) G. Peaker, P.Eng.	C. H. Riddell, P.Eng.
ICG Resources Ltd. (ICG) P. Krenkle, P.Eng.	
Independent Petroleum Association of Canada (IPAC) A. E. Potter, P.Eng.	
Simmons Pipelines Ltd. (Simmons) J. B. Ballem, Q.C.	R. A. Ursel, P.Eng. V. Redekop, C.A.
Energy Resources Conservation Board (Board staff) D. Holgate G. Dunn, P.Eng. M. Vandenbeld A. Nixon	
Alberta Environment T. Bossenberry R. Dyer	

the reserves are sufficient to justify construction of the facilities as proposed.

4 TECHNICAL DESIGN

4.1 Views of the Applicant

NOVA's proposal involved the construction of approximately 66 km of 219.1-mm pipeline as well as some 8.1 km of 168.3-mm pipeline. The proposed pipeline (Alternative 1) would extend south from the Graham and Chard areas and connect to existing NOVA facilities in the Kirby North field. The system was sized to handle a total of 1171 10^3 m^3/d (design year 1984-1985) based on a delivery pressure of approximately 8200 kPa at Kirby North.

NOVA's submission also indicated that for Alternative 2 (the Leismer lateral), delivery pressures required at Leismer would be some 1400 kPa higher and therefore the pipeline connecting Leismer with the Graham/ Chard areas would be larger (323.9 mm) than the pipeline proposed as Alternative 1. NOVA also indicated that the right of way for the Leismer case would be wider.

Another matter addressed by the applicant under questioning concerned the downstream capacity requirements for each alternative. NOVA indicated that certain looping of its system was necessary between the September Lake junction and the Hanmore compressor station. For Alternative 2, NOVA estimated that construction of this looping would be required one year earlier than for Alternative 1. NOVA also estimated that 20.2 km of loop would be required between Atmore and the Atmore junction to accommodate Alternative 2 while some 5.6 km of looping (Kirby North to Kirby North junction) was estimated to be necessary for Alternative 1.

4.2 Views of the Interveners

Simmons intervened in support of Alternative 2, indicating that in its opinion NOVA had not correctly assessed the downstream looping requirements. Simmons calculated that approximately 10 km of looping would be required between Atmore and the Atmore junction and that only a portion of the looping between September Lake junction and Hanmore, estimated by NOVA, was required to transport Graham/Chard gas.

Simmons also believed that the estimated pipeline-length topographic allowance was not consistent between the two cases. Simmons contended that if equivalent allowances were used, the length of laterals in Alternative 2 would be reduced by 2.3 km.

None of the other interveners commented on design aspects of the pipeline.

4.3 Views of the Board

The Board has reviewed the evidence presented and concurs that the design criteria used by NOVA is appropriate. The Board is generally in agreement with the pipeline sizing as proposed by NOVA with regard to the alternative laterals. The Board acknowledges that a wider right of way may be necessary for the lateral to Leismer, and it agrees that topographic allowances should be consistent and has made some allowance for this (see section 5).

With regard to downstream looping, the Board has reviewed this matter in some detail and concludes that in either case some downstream looping would be necessary. According to Simmons' calculations, some 10 km would be the minimum looping necessary to carry the Graham/Chard volumes via the Leismer-Atmore route. Alternately, the Board notes that some 5.6 km of smaller pipeline looping would be necessary in the Kirby area to handle the same volumes using NOVA's proposed facilities.

The Board has reviewed the remaining aspects of the technical design and believes that the design meets requirements prescribed in The Pipeline Act, 1975.

5 ECONOMIC CONSIDERATIONS

5.1 Views of the Applicant

NOVA stated that its proposed facility (Alternative 1) provided the lowest cost of service compared to four other alternatives considered.

NOVA set out cost-of-service calculations for five alternatives to illustrate its case, and confirmed that the cost-of-service figures included all applicable new facilities, incremental operating costs, and also the Simmons tariff for Alternatives 2 and 5. Three of the alternatives involved various combinations of pipeline sizing and compression via the Kirby North route, while the other two alternatives tabulated the costs for two combinations of pipeline size and compression via Leismer.

Under questioning by Simmons, NOVA did not agree that a share of capital costs associated with existing downstream facilities should be allocated to the new gas from the Graham/Chard area. Simmons contended that it was necessary to compare all capital and operating costs to a common point on the system when comparing alternatives. NOVA responded by indicating that downstream costs must be considered as sunk costs and that all costs to NOVA, including the full Simmons tariff (where applicable), were included in NOVA's cost-of-service comparisons.

NOVA provided a full set of comparative cost-of-service calculations to a common point (Smoky Lake) which included necessary downstream facilities to handle combined system volumes for the two alternatives in question. NOVA's cost estimates associated with the facilities are summarized in Table 2.

TABLE 2 COMPARISON OF CAPITAL COSTS
KIRBY VS LEISMER LATERALS
Thousands of dollars

Alternative 1: Kirby

			Looping*	No Looping
	Pipelines			
	- 13.6 km x 219.1 mm	Graham to Chard Jct	1 743	1 743
	- 8.1 km x 168.3 mm	Chard to Chard Jct	870	870
	- 52.5 km x 219.1 mm	Chard Jct to Kirby North	6 410	6 410
*	- 5.6 km x 219.1 mm	Loop Kirby N to Kirby N Jct	725	-
		Subtotal	9 748	9 023
	Metering			
	- at Graham		230	230
	- at Chard		120	120
		Total	10 098	9 373

Alternative 2: Leismer

			Looping*	No Looping
	Pipelines			
	- 15.9 km x 323.9 mm	Graham to Chard	2 797	2 797
	- 42.5 km x 323.9 mm	Chard to Leismer Lateral	7 632	7 632
	- 20.2 km x 323.9,mm loop,	Atmore to Atmore Jct	3 145	3 145
*	- 38.1 km x 406.4 mm loop,	Hanmore Compressor St. - to Smoky Lake	7 962	-
		Subtotal	13 574	10 429
	- at Graham		230	230
	- at Chard		120	120
	- at Leismer		250	250
	- at Atmore		250	250
		Total	14 424	11 279

NOTE:

Looping from September Lake to Smoky Lake not included; common to both cases.

5.2 Views of the Interveners

Simmons contended that part of the capital costs of the existing Kirby lateral should have been allocated as a cost for transporting Graham/Chard gas. Also, as mentioned earlier, Simmons contested the capacity of the loop between Atmore and the Atmore junction assumed by NOVA in its calculations. Simmons indicated that, in its opinion, only 10 km of loop was required to move the Graham/Chard volumes and therefore, the full-length looping costs should not be included in the Alternative 2 economic calculation. In addition, Simmons stated that the cost of only 15 km of the September Lake - Hanmore loop should be allocated to Alternative 2.

Other interveners who spoke to the matter generally were opposed to Alternative 2 supported by Simmons, since NOVA's cost-of-service estimates indicated that there could be a surcharge to producers associated with that alternative.

Although IPAC suggested that a one-time, up-front contribution in lieu of a surcharge may be appropriate in some cases where the cost of service was high, Pan-Alberta opposed the surcharge. Neither Pan-Alberta nor IPAC commented on the economic analysis used. Occidental, Paramount, Petrobolt Resources and ICG favoured NOVA's Alternative 1 proposal, as applied for, and opposed Alternative 2 since the latter would mean a delay in marketing the gas and result in a possible surcharge.

5.3 Views of the Board

First, with regard to the matter of allocated downstream looping costs, the Board has reviewed the evidence and concludes that, in general, NOVA has properly accounted for applicable downstream costs associated with each alternative.

Although the Board believes that Simmons may be correct in its assessment of the Atmore - Atmore junction loop, it notes that, even without any looping between Atmore and the Atmore junction, the capital costs associated with Alternative 2 as supported by Simmons are higher than with Alternative 1 including the necessary looping on the Kirby lateral. Other downstream looping was common to both cases except for the timing of construction. However, the Board believes that these factors have been equitably accounted for. The Board considers that the NOVA cost-of-service calculations have accounted for all new capital costs.

Regarding Simmons' view that some portion of the capital costs associated with existing downstream facilities (to a common point) should be included in the economic analysis, the Board generally agrees with the argument. It believes that, even though existing facilities represent sunk costs, an equitable comparison can be made of the alternatives. In this case, since the Board did not receive any information respecting sunk costs, it chose to compare Alternatives 1 and 2 by deducting the capital portion of the Simmons pipeline tariff from the operating costs tabulated by NOVA under

Alternative 2. The Board believes that this approach provides an equitable comparison since this in essence deletes tariff attributable to the sunk costs on the Simmons system. The Board notes that NOVA included costs for looping downstream from the Simmons system, sufficient to handle the volumes and therefore believes that the NOVA comparison is valid. On the basis of the comparison described above, the Board estimates that the operating and maintenance costs are nearly identical in each case, and therefore concludes that there is little ecomomic difference between the two alternatives.

In summary, the Board concludes that there is only a marginal economic difference between Alternatives 1 and 2 - a difference too small to justify a decision on the basis of economic considerations alone.

6 ENVIRONMENTAL CONSIDERATIONS

6.1 Views of the Applicant

NOVA provided an environmental impact assessment of its proposed route (Alternative 1). This report outlined the various facets of the environment that may be affected, together with the company's plan to protect and restore the environment. NOVA stated that no major watercourses were intersected. NOVA did concede under questioning from interveners that the proposed pipeline may have slightly more environmental impact than Alternative 2, since the route was slightly longer.

6.2 Views of the Interveners

Only one intervener, Simmons, offered any comments respecting environmental matters. Simmons agreed that little difference existed between the two alternatives from an environmental point of view. It was pointed out that Alternative 2 did involve one or two minor stream crossings whereas Alternative 1 did not.

6.3 Views of the Board

The Board agrees with the applicant and interveners that there would be little difference in environmental impact between Alternatives 1 and 2.

7 ORDERLY DEVELOPMENT

7.1 Views of the Applicant

NOVA claimed that extending the Kirby lateral would represent a logical and orderly development of its system to provide pipeline service to the Graham/Chard areas.

7.2 Views of the Interveners

Simmons argued in its intervention that connection of the reserves in the Graham and Chard areas via the Leismer-Simmons system (Alternative 2) would be more orderly and more in the public interest than would the proposal made by NOVA. It was Simmons' contention that there was some advantage to having the Graham/Chard reserves connected to the Simmons system to facilitate increased gas deliveries north to serve potential markets in the Fort McMurray area. Under questioning from NOVA, Simmons agreed that the timing of future energy projects in the Fort McMurray area was speculative, and could give no definite volume build-up schedule for those potential projects.

7.3 Views of the Board

The Board notes that Simmons will have access to significant new gas reserves as a result of the Board's decision respecting Application 810600 (Liege lateral). Also, the Board notes that gas contracts associated with the Graham/Chard areas are export contracts, and believes that the ultimate destination of those reserves will be southward rather than northward. Since the Board considers that future energy projects near Fort McMurray may not necessarily rely heavily on gas to recover synthetic crude, it does not view the Simmons' argument as crucial at this time.

The Board therefore considers that either Alternative 1 or 2 would represent orderly development of the pipeline system in the general area.

8 TIMING AND IMPACT ON INDUSTRY

8.1 Views of the Applicant

NOVA stated that early approval of the proposed pipeline was necessary to assure construction of the pipeline during the coming winter season, thereby allowing producers an opportunity to commence gas shipments during the 1982-83 contract year. NOVA said that if its application was denied, considerable time would be required to prepare and submit another application, and the company would miss the winter construction season. It was NOVA's view that if this happened the producers affected would experience a 6-month delay in production start-up and gas sales.

8.2 Views of the Interveners

The producers strongly supported NOVA's application and emphasized their views regarding early approval, since delays in pipeline start-up would mean delays in production and associated cash flows. Pan-Alberta

supported the producers' position and indicated that the Graham/Chard gas would add to Pan-Alberta's east-leg supply, and would give access to substantial new reserves, thereby benefitting the province. In the opinion of Pan-Alberta, NOVA's application provided the quickest and most economic method of marketing the reserves under contract.

8.3 Views of the Board

In reviewing the evidence, the Board is cognizant of the requirements of The Pipeline Act, 1975, that the facility must be "economic and orderly". In this case the Board has weighed the economic factors carefully and sees very little difference between Alternative 1, proposed by the applicant, and Alternative 2, supported by Simmons.

However, the Board does see some economic impact with respect to the timing of each alternative. In the Board's view, this impact may be particularly important to small producers and therefore considers NOVA's application more appropriate. Earlier production royalties collected by the province would be of some benefit, and the Board recognizes that the ability of industry to explore for and produce oil and gas is a function of the cash flow resulting from gas sales. The Board believes that this in turn has an overall positive effect on the public interest and therefore concurs with NOVA's position on this matter.

9 SUMMARY OF BOARD VIEWS

The Board has weighed the information on each of the issues discussed and in this case finds that the NOVA's application is in the public interest. It appears that the pipeline would be available when required to meet contractual commitments and to allow producers earlier market access. Although the Board has made no attempt to quantify the costs associated with a one-year construction delay, it recognizes these effects could be substantial. While economic comparisons indicate little difference between Alternatives 1 and 2, the factor of timing does impart some economic advantage to Alternative 1.

The Board also concludes there is little difference in other aspects of the two alternatives. All participants agreed that environmental effects would be similar and the Board does not agree with the suggestion that increased capacity to the north would lend some advantage to tying into the Leismer lateral (Alternative 2).

10 DECISION

For the reasons outlined, the Board is prepared to grant a permit to construct the facilities as applied for.

The permit will be issued subject to the approval of the Minister of the Environment regarding environmental matters.

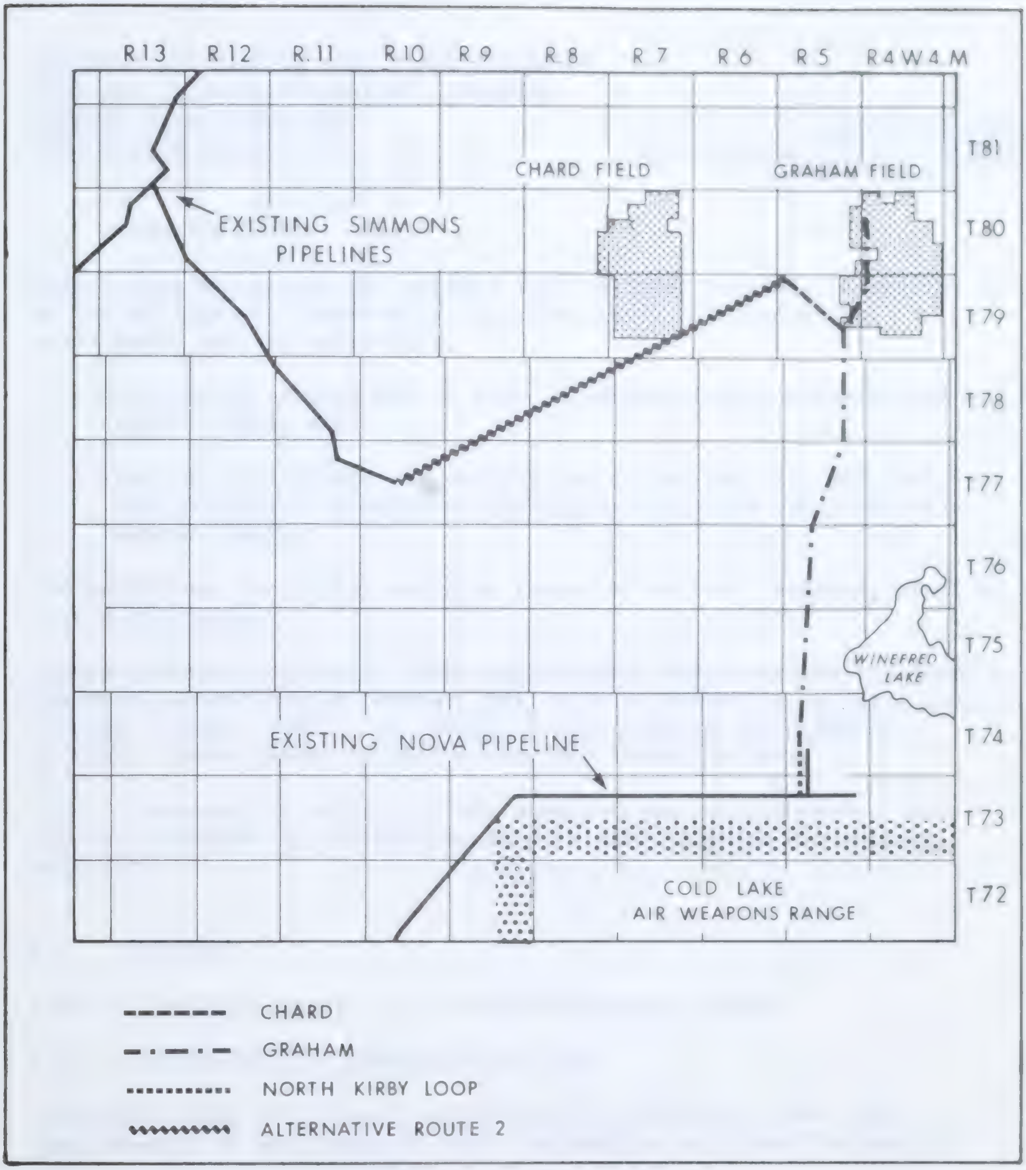
ISSUED at Calgary, Alberta on 26 January 1982.

Energy Resources Conservation Board

G. J. DeSorcy
Vice Chairman

V. E. Bohme
Board Member

F. Trofanenko
Acting Board Member



NOVA, AN ALBERTA CORPORATION.
APPLICATION NO. 810576
CHARD / GRAHAM AREA.

FIGURE 1

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

Alberta

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

CHLORINE AND CAUSTIC SODA PLANT EXPANSION
ETHYLENE DICHLORIDE AND VINYL CHLORIDE-
MONOMER PLANT EXPANSION
DOW CHEMICAL CANADA INC.

Decision 82-5
Applications 810042 & 810043

1 APPLICATIONS

This report deals with two related applications, pursuant to section 42 of The Oil and Gas Conservation Act (The Act)[1], for industrial development permits authorizing

- the use of natural gas as fuel for production of chlorine and caustic soda, and
- the use of ethylene and natural gas as raw material and fuel for production of ethylene dichloride (EDC) and vinyl chloride monomer (VCM).

The additional facilities would be installed at Dow's existing plant at Fort Saskatchewan.

Representations respecting these applications were heard by the Board in Edmonton, Alberta on 20 October 1981, with N. Berkowitz, P.Eng., C. J. Goodman, P.Eng., and G. A. Warne, P.Eng. (acting Board Member), sitting. Participants at the hearing are listed in Table 1.

AGEC, intervened in support of the applications, and AEC/DuPont and AEC/Esso appeared at the hearing only to cross-examine and present argument.

2 FINDINGS

From the evidence before it, the Board finds as follows:

2.1 AVAILABILITY OF FEEDSTOCK AND FUEL

Sufficient supplies of gas are available in Alberta to meet the requirements of both proposed plant expansions and, notwithstanding

1 Now section 30 of the Oil and Gas Conservation Act, RSA 1980.

TABLE 1

TABLE OF HEARING PARTICIPANTS

Principals and Representatives (Abbreviations used in Report)	Witnesses
Dow Chemical Canada Inc. (Dow) C. K. Yates	C. L. Mort M. F. Boode R. S. Daniels, P.Eng. D. J. Kostash, P.Eng. D. A. Lauzon, P.Eng. R. W. Lutz E. J. Mattern
Alberta Energy Company Ltd. and DuPont Canada Inc. (AEC/DuPont) D. Wood	
Alberta Energy Company Ltd. and Esso Chemical Canada (AEC/Esso) A. J. Wiggins	
The Alberta Gas Ethylene Company Ltd. (AGEC) F. R. Foran	
Alberta Environment F. V. Witthoeft, P.Eng.	
Energy Resources Conservation Board staff D. A. Holgate D. G. Pearson, P.Eng. K. Johnston M. E. Mumby	

a possible short-term deficiency of ethylene in 1985, long term supplies of ethylene are also expected to suffice for the expansion of the EDC/VCM plant as well as existing and approved projects.

Coal is not an economic fuel for the complex at Fort Saskatchewan at this time.

2.2 EFFICIENT USE OF ENERGY RESOURCES

The processes which the applicant would use in the proposed plant expansions comprise proven commercial technologies and would make efficient use of energy resources.

2.3 ECONOMIC IMPACT

Alberta resources required for construction and operation for the incremental chlorine and caustic soda production are estimated to be 470 million in 1980 dollars and the net benefits accruing to Alberta from the project would be $152 million. The total direct economic impact on Alberta over the 20 year life of the project is estimated at $621 million. Income/expenditure multiplier effects would increase this impact.

The value of resources and material required for incremental production of ethylene dichloride and vinyl chloride would amount to $587 million, while the net benefits to Alberta would be $58 million. The total economic impact of this plant expansion on Alberta would be some $645 million. Any income/expenditure multiplier effects would increase the impact.

2.4 MARKETS AND UPGRADING

While current economic conditions indicate little growth of demand for vinyl chloride monomer during the next few years, the combination of relatively low cost fuel and feedstocks and the applicant's marketing expertise should ensure the commercial viability of the projects.

2.5 ENVIRONMENTAL IMPACT

Notwithstanding the applicant's best efforts to minimize harmful emissions, there remain some concerns over potential health hazards from plant emissions. The applicant in consultation with Alberta Environment should establish a monitoring system to maintain the plant operations under continuous surveillance.

3 DECISIONS

3.1 CHLORINE AND CAUSTIC SODA PLANT

Having regard for its findings and responsibilities under the Act, the Board is prepared, with the approval of the Lieutenant Governor in Council, to grant the application for amendment of Industrial Development Permit No. DCC 80-7 for a term of 20 years. The permit would be in the form shown in Appendix A, and subject to all of the terms and conditions contained therein and to any terms and conditions imposed by the Lieutenant Governor in Council.

3.2 ETHYLENE DICHLORIDE AND VINYL CHLORIDE PLANT

The Board is similarly prepared, with the approval of the Lieutenant Governor in Council, to grant the application for amendment of Industrial Development Permit No. DCC 80-5 for a term of 20 years. The permit would be in the form shown in Appendix B, and subject to all of the terms and conditions contained therein and to any terms and conditions imposed by the Lieutenant Governor in Council.

ISSUED at Calgary, Alberta on the 22th day of March 1982.

ENERGY RESOURCES CONSERVATION BOARD

N. Berkowitz, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

G. A. Warne

G. A. Warne, P.Eng.
Acting Board Member

REASONS FOR DECISIONS

4 CHLORINE AND CAUSTIC SODA PLANT APPLICATION NO. 810042

4.1 APPLICATION

Dow requested an amendment of Industrial Development Permit No. DCC 80-7, which would authorize the use of an additional 131 x 10^6 cubic metres (m^3) of gas per year as fuel for incremental production of 232 x 10^3 tonnes per year of both chlorine and caustic soda in an expansion of existing facilities at Fort Saskatchewan. The expanded plant would use 359.4 x 10^6 m^3 of gas per year for annual production of 549.5 x 10^3 tonnes each of chlorine and caustic soda. A permit term of 20 years, commencing with start-up of the expanded facilities projected for 1984, was requested.

4.2 ISSUES

Having regard for its responsibilities under section 30 of the Act, the Board considers the issues raised by the application for expansion of the plant to be:

- the availability and efficient use of energy resources,
- the economic impact on Alberta,
- the marketing and upgrading potentials of the incremental product volumes, and
- the environmental impact of the expanded plant.

4.3 AVAILABILITY OF FUEL

Views of Dow

Dow submitted that sufficient gas would be available for the proposed expanded plant and that this gas would be purchased from Northwestern Utilities Limited and/or other independent Alberta producers. The additional 131 x 10^6 m^3 of gas per year includes a 15 per cent contingency which allows for expected operation of the plant above design capacity.

Views of the Board

The Board agrees that supplies of gas in Alberta will be sufficient to meet Dow's additional needs (2.62 x 10^9 m^3) over the applied-for permit term, but would require the applicant to satisfy it, prior to plant start-up, that satisfactory arrangements for gas deliveries to the plant site have been made.

4.4 EFFICIENT USE OF ENERGY RESOURCES

Views of Dow

The production process to be used in the proposed expansion requires natural gas to raise steam for additional caustic evaporators, and, while generally similar to the process used in the existing plant, would incorporate some technical improvements. Dow noted in particular that the package boilers for steam generation would operate at greater than 85 per cent efficiency and together with extensive cross-exchange and heat recovery systems, would minimize energy requirements.

Electrical energy for the expansion would be supplied from existing on-site capacity or from off-site sources.

Views of the Board

In light of the applicant's experience in producing chlorine and caustic soda, and having regard for the evidence before it, the Board agrees that the proposed expansion would employ the latest proven commercial technology, and use energy resources efficiently.

4.5 ECONOMIC IMPACT

Views of Dow

The applicant estimated the construction costs* of the proposed chlor-alkali/caustic soda expansion to be about \$160 (\$109) million, and provided for an additional \$26.2 (\$18) million as working capital.

Total revenues were estimated to be \$2197 (\$1500) million; operating costs were given as \$1017 (\$694) million; and the after-tax net income was calculated to be about \$442 million in 1980 dollars.

The direct impact on the Alberta economy would include 50 per cent of construction costs and 70 per cent of operating costs. In addition, provincial and municipal taxes, and the project's entire after-tax net income were considered to impact on the Alberta economy. The total direct impact on the Alberta economy was estimated to be \$1316 (\$899) million and assuming an income/expenditure multiplier of 2.0, Dow estimated the combined direct and indirect impact to be \$2632 (\$1978) million.

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* While Dow presented its economic data in terms of 1984 dollars, the Board has, for the purposes of this report deflated these to 1980 dollars using a ten per cent inflation factor. The figures submitted by the applicant are therefore presented with their 1980 equivalent in parentheses.

Construction of the facilities would take 2 years, and require a peak construction crew of 145 people. The project would have a permanent workforce of 14 people.

Views of the Board

The Board's forecast of the potential economic effects of the proposed expansion incorporates Dow's estimates of capital costs and working capital, but assumes 100 per cent flow-through of taxes, an investment tax credit of 7 per cent, a long-term average interest rate of 15 per cent, and a long-term average inflation rate of 10 per cent. Its findings on this basis are presented in Table 2, in which the upper portion relates to economic viability, and the lower to potential impact on Alberta's economy. All values are in constant 1980 dollars.

The Board's analysis indicates an after-tax net income of about $822 million, or roughly twice Dow's estimate of $422 million.

The value of Alberta resources used during construction and operation of the project would be some $470 million, and net benefits accruing to the province, primarily from provincial and municipal taxes, would amount to approximately $152 million. (The Board notes that the project expansion requires no immediate government expenditures on public infrastructures or services). In the Board's opinion, only a negligible fraction of after-tax net income would accrue to Alberta shareholders.

The total economic impact on Alberta would be about $621 million, and on the basis of Dow's estimate of an income/expenditure multiplier of 2.0 which the Board accepts for its purposes, the combined direct and indirect effect is estimated at $1242 million over the 20-year life of the project.

4.6 MARKETS AND UPGRADING

Views of Dow

Dow indicated that the incremental chlorine production would be used mostly in the manufacture of ethylene dichloride. Any surplus would be marketed in western Canada, but was not expected to be significant. Most of the incremental caustic soda would be marketed in western Canada, "...for use by the pulp and paper industry, the oil and gas industry, oil sands plants, and other incidental uses". Dow noted an emerging end-use for caustic soda in the recovery of heavy oil, and believed that this would provide an important market in the next few years, but indicated that caustic soda surplus to western Canadian needs would, at least initially, be sold in other North American and Pacific Rim markets.

TABLE 2 BOARD ESTIMATE OF ECONOMIC VIABILITY AND IMPACT OF THE PROPOSED EXPANSION OF THE CHLORINE AND CAUSTIC SODA PLANT millions of constant, 1980 dollars

Total Costs and Revenues of the Proposed Project		
Revenues		$1 939.0
Expenditures		
Construction Costs		109.2
Operating Costs		52.2
Interest*		31.0
Municipal Taxes		4.4
Fuel		378.2
Net Income Before Income Taxes		1 364.0
Income Taxes		
Provincial		147.1
Federal		394.7
Net Income		822.2
Alberta Impact		
Resource Using Expenditures		
Capital Expenditures		54.6
Operating Expenditures		
Fuel		378.2
Other		36.5
	Sub-total	469.3
Net Benefits (Exclusive of Resource Costs)		
Shareholders' Income		-
Provincial Income Tax		141.1
Municipal Tax		4.4
	Sub-total	151.5
	Total	620.8

* These represent inflation-adjusted interest payments.

Views of the Board

The Board observes that Dow intends to use most, if not all, of its chlorine within its own organization, and that, the market outlook for chlorine ultimately depends upon demand for ethylene dichloride and vinyl chloride monomer. This matter is discussed in section 5.6.

With respect to caustic soda the Board is satisfied that current and projected market developments justify additional production.

4.7 ENVIRONMENTAL IMPACT

Views of Dow

In response to questions by Alberta Environment staff, the applicant observed that the proposed expansion would allow installation of improved control technology, and that stack emissions of hydrogen chloride and chlorine would not exceed the limits stipulated in its current license. It believed, indeed, that the level of such emissions could be substantially lowered.

Because of plant maintenance techniques presently in use, fugitive emissions of hydrogen chloride and chlorine would be unexpected occurrences under normal operating conditions, and systems have been installed to reduce the potential for chlorine emissions due to equipment failure or similar unpredictable events. These systems include a separate diesel-electric facility which automatically supplies power to scrubber pumps, emergency block valve systems which isolate process sections, and a computer assisted preventive maintenance program which monitors piping and equipment reliability.

Dow stated that its comments with respect to stack emissions and fugitive emissions were based on performance of the existing plant, which more than adequately met the half hour maximum ground level concentration guideline of 0.1 parts of chlorine per million of air. Chlorine emission sources include hydrogen vents, hydrochloric acid burners, a tail gas scrubber, an acidizing tank vent, and a dump scrubber. The proposed expansion would not require any additional vents.

Views of the Board

The Board's views respecting both proposed plant expansions are contained in section 5.7.

5 ETHYLENE DICHLORIDE/VINYL CHLORIDE (EDC/VCM) PLANT APPLICATION NO. 810043

5.1 APPLICATION

Dow's requested amendment of Industrial Development Permit No. DCC 80-5, would authorize the annual use of an additional 118 x 10^3 tonnes of ethylene as feedstock and 23 x 10^6 m^3 of gas as fuel for annual production of an additional 460 x 10^3 tonnes of ethylene dichloride (EDC) and 365 x 10^3 tonnes of vinyl chloride monomer (VCM) in expanded facilities at Fort Saskatchewan. The expanded plant would annually use 353 x 10^3 tonnes of ethylene and 105 x 10^6 m^3 of gas to produce 530 x 10^3 tonnes of ethylene dichloride and 420 x 10^3 tonnes of vinyl chloride monomer. The term requested for the permit was 20 years, commencing with start-up of the expanded facilities, projected for 1984.

5.2 ISSUES

Having regard for its responsibilities under section 30 of the Act, the Board considers the issues raised by the application for expansion of the plant to be:

- the availability and efficient use of energy resources,
- the economic impact on Alberta,
- the marketing and upgrading potentials of the incremental product volumes, and
- the environmental impact of the expanded plant.

5.3 AVAILABILITY OF FEEDSTOCK AND FUEL

Views of Dow

Dow's ethylene supply/demand balance (see Table 3) for the period 1982-1988 included the output of three Alberta Gas Ethylene plants as supply, and its own projected ethylene requirements plus the nameplate capacity requirements of other derivative plant proposals heard by the Board as the demand. The applicant's requirements include ethylene which it expects to continue moving to its Sarnia operations through the Cochin pipeline under an existing agreement with the Government of Alberta. Dow considered these quantities to be committed for removal from Alberta.

TABLE 3

DOW CHEMICAL CANADA INC.

ALBERTA

ETHYLENE SUPPLY/DEMAND BALANCE

kilotonnes/year

	1982	1983	1984	1985	1986	1987	1988
AGE I	544	544	571	598	598	598	598
AGE II			181	612	680	680	680
AGE III				181	612	680	680
TOTAL SUPPLY	544	544	752	1391	1890	1958	1958
DOW*	460	460	503	689	885	903	903
DOW RESALE	84	84	140	202	148	148	148
UCCL			42	126	140	140	140
AEC/DUPONT				78	178	212	222
AEC/ESSO				31	104	116	116
SHELL NOVA P.E.			65	195	260	260	260
SHELL NOVA STY			26	76	85	85	85
CIL				28	103	103	103
CEL				43	145	161	161
TOTAL DEMAND	544	544	766	1468	2048	2128	2138
BALANCE	0	0	(24)	(77)	(158)	(170)	(180)

* Includes exports from Alberta up to 227 kilotonnes/year.

October 19, 1981

Also included in Dow's requirements is ethylene which it agreed to supply to Canadian Industries Limited (CIL) and Celanese Canada Inc.; some of this would come from Dow's present AGE I receipts, and some from storage at Fort Saskatchewan. Dow also included the ethylene needed for a proposed expansion of its ethylene oxide/ethylene glycol (EO/EG) plant at Fort Saskatchewan*.

In viewing the ethylene balance in Alberta, Dow considered it important to note that only minimal shortfalls of ethylene are likely before 1986. This view was based on the probability that an announced fourth ethylene plant would be constructed in Alberta by 1986, and on the fact that derivative plants, even with good market conditions, generally do not operate at greater than 95 per cent of name plate capacity. The shortfalls of ethylene supply recognized by Dow in 1984 and 1985 were 24 and 77 kilotonnes, respectively, and larger deficiencies in 1986 and beyond would be accommodated by the announced fourth ethylene plant.

Dow also submitted that sufficient gas is available to meet the additional fuel requirements of the proposed expanded EDC/VCM plant.

In response to a Board request the applicant supplied further information on the use of coal as a fuel. Dow contended that coal would have to be delivered at a negative cost in order to be competitive with natural gas under the present conditions, and that it would likely not be economical as fuel for the Fort Saskatchewan area before the late 1990's at the earliest.

Views of the Board

The Board's review of ethylene supply and demand in Alberta for the period 1982 to 1989 is shown on Table 4 and includes supplies from three Alberta Gas Ethylene plants which have been approved by the Board. The demand forecast recognizes the feedstock requirements of all existing and approved ethylene upgrading plants, including those awaiting Order in Council, as well as the requirements of Dow's proposed EDC/VCM plant expansion, but no allowances were made for the proposed expansion of the EO/EG plant.

Notwithstanding Dow's position regarding the quantities removed through the Cochin pipeline, the Board continues to assume that all ethylene produced in Alberta would, if required, be available for use in the province, and consequently made no allowances for removal volumes.

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* An application for expansion of the EO/EG plant has been filed and the Board is currently awaiting submission of additional information.

TABLE [illegible] ALBERTA ETHYLENE SUPPLY/REQUIREMENTS BY YEAR 1982-1989
(10^3 tonnes/year)

A SUPPLY

COMPANY	STATUS	1982	1983	1984	1985	1986	1987	1988	1989	DESIGN CAPACITY
1 Alberta Gas Ethylene #1	Operating	552	552	584	617	626	626	626	626	544
2 Alberta Gas Ethylene #2	Permit Issued	-	-	328	635	725	748	748	748	680
3 Alberta Gas Ethylene #3	Awaiting O.C.	-	-	-	205	635	725	748	748	680
	Cumulative Lines 1-3	552	552	912	1 457	1 986	2 099	2 122	2 122	

B REQUIREMENTS

COMPANY	PRODUCT	STATUS	1982	1983	1984	1985	1986	1987	1988	1989	DESIGN CAPACITY
1 Canadian Industries Limited	Polyethylene #1	Operating	35	35	35	35	35	35	35	35	35
2 Celanese	Vinyl Acetate	Operating	23	23	23	23	23	23	23	23	23
3 Dow Chemical	Ethylene Glycol	Operating	157	157	157	157	157	157	157	157	157
4 Dow Chemical	Ethylene Dichloride/ Vinyl Chloride	Operating	235	235	235	235	235	235	235	235	235
		Cumulative Lines 1-4	450	450	450	450	450	450	450	450	
5 Canadian Industries Limited	Polyethylene #2	Permit Issued	25	35	35	35	35	35	35	35	35
6 AEC/Esso	Styrene	Permit Issued	-	-	-	97	114	114	114	114	114
7 Enesco Chem	Styrene	Permit Issued	-	-	15	67	85	89	98	98	85
8 Dow Chemical	Polyethylene	Permit Issued	-	-	125	175	184	203	203	203	175
9 Enesco Chem	Polyethylene	Permit Issued	-	-	65	195	260	273	300	300	260
10 Union Carbide	Ethylene Glycol	Permit Issued	-	-	35	105	141	148	162	162	141
11 Canadian Industries Limited/Trimac	Polyethylene #3	Permit Issued	-	-	41	82	102	105	111	111	102
		Cumulative Lines 1-11	475	485	766	1 206	1 371	1 417	1 473	1 473	
12 AEC/Du Pont	Polyethylene	Awaiting O.C.	-	-	78	138	212	223	238	238	221
13 Celanese	Vinyl Acetate	Awaiting O.C.	-	-	-	56	137	161	161	161	161
14 Dow Chemical	Ethylene Dichloride/ Vinyl Chloride	Awaiting O.C.	-	-	42	84	103	108	118	118	103
		Cumulative Lines 1-14	475	485	886	1 524	1 823	1 909	1 990	1 990	
BALANCE (deficiency)			77	67	26	(67)	163	190	132	132	

On this basis, a short-term deficiency of approximately 67 kilotonnes of ethylene may appear in 1985 (see Table 4). The Board agrees with Dow that derivative plants do not usually operate at maximum capacity, and that any shortfalls before 1986 would therefore likely have minimal effects. However, if the Board's assumption respecting currently exported volumes of ethylene proves incorrect, a substantial shortage would occur in 1984 and make itself felt until a fourth ethylene plant commences full operation.

Overall, the Board concludes that, in the long term, sufficient supplies of ethylene will be available to meet the requirements of all existing and approved ethylene upgrading facilities, as well as the proposed expansion of Dow's EDC/VCM plant. But it emphasizes that provincial demand for ethylene will probably reach the level of projected supplies in the 1984-85 period, and that any delay in the start-up of planned ethylene-producing facilities could seriously tighten supply. The Minister of Economic Development may well need to exercise his discretion in allocating ethylene to existing and proposed users if that occurs.

On the other hand, supplies of gas in Alberta are more than sufficient to meet Dow's needs over the applied for term of permit, but if a permit were issued, the Board would require Dow to satisfy it, prior to plant start-up, with respect to arrangements made for the required gas supply.

The Board agrees that coal is not an economic fuel in the Fort Saskatchewan complex at this time.

5.4 EFFICIENT USE OF ENERGY RESOURCES

Views of Dow

The EDC/VCM manufacturing process which would be used in the proposed expansion is the same as that now used by the applicant at its Fort Saskatchewan site, but overall energy efficiency would be improved through greater heat recovery.

In the process, ethylene is directly chlorinated to EDC and then pyrolysed to VCM and hydrogen chloride. The hydrogen chloride is subsequently reacted with oxygen and ethylene to produce a second stream of EDC. Extensive energy conservation measures would be taken to minimize energy consumption and ensure the efficient use of fuel gas in the plant. This would be accomplished by installing furnaces which operate at thermal efficiencies of approximately 90 per cent; by extensive cross-exchange of hot and cold process streams; by furnace flue gas heat recovery; and by "double effect" distillation columns.

The energy efficiency of the expanded EDC/VCM operation would be 86.7 per cent, or some 9.5 per cent higher than the calculated efficiency of the existing plant. Dow noted that its application shows saleable EDC as a product, and, since the energy efficiency of manufacturing EDC is much higher than for VCM, that a weighted ratio of these products was used to calculate the overall 86.7 per cent efficiency.

Views of the Board

Dow's experience of converting ethylene and chlorine to EDC and VCM, and its commitment to incorporate sound energy conservation principles in the design of proposed plant expansion, leads the Board to conclude that the EDC/VCM expansion would utilize up-to-date commercial technology and use energy resources efficiently.

5.5 ECONOMIC IMPACT

Views of Dow

Dow estimated* the capital costs to be $59.7 ($41) million, and allowed an additional $73.3 ($50) million for working capital.

The project's total revenues were estimated at $4109 ($2807) million, and total operating costs at $3248 ($2218) million.

The direct impact on the Alberta economy would include 73 per cent of construction costs and 65 per cent of operating costs, the latter including expenditures on fuel, feedstock, utilities, labour, maintenance and material, as well as depreciation. In addition, provincial corporate income taxes, municipal taxes, and the project's entire (after-tax) net income were considered to be impacts. The direct impact of the project was consequently estimated to be $968 ($661) millions; and using an income/expenditure multiplier of 2.0, the total direct and indirect impact was put at $1936 ($1322) million. Provincial corporate income taxes were calculated to be $82 ($56) million, and municipal taxes, assumed to amount to $250 000 per year over the life of the project, would total approximately $1.5 ($1.0) million.

Dow's estimate of after-tax net income from the proposed expansion was about $287 million (1980 dollars) but a negligible fraction of this would accrue to Alberta shareholders.

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* As noted in section 4.5, the applicant's data are in 1984 dollars, and their equivalent 1980 dollars are shown in parentheses.

Construction of the proposed project would require 4 years, and have a peak manpower requirement of 250 people. Operation of the EDC/VCM plant expansion would require a full time staff of 8 people.

Views of the Board

The Board's evaluation of the potential economic effects of the proposed project incorporated the applicant's estimates of capital costs, working capital, and municipal taxes, but assumed 100 per cent flow-through of taxes, an investment tax credit of 7 per cent, a long-term average interest rate of 15 per cent, and a 10 per cent long-term average inflation rate. The results thus obtained are set out in Table 5, in which the upper portion relates to economic viability, and the lower to economic effects on the Alberta economy. All values are in terms of constant 1980 dollars.

The Board's analysis suggests that, despite a relatively conservative revenue forecast, the project would be profitable and yield an after-tax net income in excess of $300 million.

The value of resources, material, and labour purchased in Alberta would amount to some $587 million, while net benefits to Alberta, mostly comprised of provincial and municipal taxes, would be in the order of $58 million. In deriving these estimates, the Board assumed that the project would require no additional public infrastructures or services, and that a negligible amount of the after-tax net income would accrue to Alberta shareholders.

The total economic impact on the Alberta economy would be some $645 million, and using an income/expenditure multiplier of 2.0 the combined direct and indirect impact would be $1290 million over the 20-year life of the project.

5.6 MARKETS AND UPGRADING

Views of Dow

Dow is currently the only Canadian producer of ethylene dichloride and vinyl chloride monomer, and provides feedstock for the three Canadian producers of polyvinyl chloride. The applicant was confident that a strong market for ethylene dichloride and vinyl chloride monomer would exist throughout the permit term of the proposed expansion. It expected to export a large part of its expanded output to United States and Pacific Rim markets in the initial years of production, but believed that a growing Canadian market would eventually utilize a much more significant portion of the output.

TABLE 5 BOARD ESTIMATE OF ECONOMIC VIABILITY AND IMPACT OF THE PROPOSED EXPANSION OF THE EDC/VCM PLANT
millions of constant, 1980 dollars

Total Costs and Revenues of the Proposed Project		
Revenues		$1 921.0
Expenditures		
Construction Costs		41.0
Operating Costs		28.4
Interest*		9.0
Municipal Taxes		1.0
Fuel and Feedstock		1 313.4
Net Income Before Income Taxes		537.2
Income Taxes		
Provincial		57.4
Federal		153.8
Net Income		326.0
Alberta Impact		
Resource Using Expenditures		
Capital Expenditures		30.0
Operating Expenditures		
Fuel and Feedstock		539.0
Other		18.0
	Sub-total	587.0
Net Benefits (Exclusive of Resource Costs)		
Shareholders' Income		-
Provincial Income Tax		57.0
Municipal Tax		1.0
	Sub-total	58.0
	Total	645.0

* These represent inflation-adjusted interest payments.

Views of the Board

The Board is less confident than Dow that demand for VCM will be very buoyant during the next few years. It believes that the current economic conditions do not augur well for any product whose principal markets are in the construction and automobile industries, and that, even later, during economic recovery, there will be a period of adjustment in which excess inventories will be reduced and idle capacity utilized.

This outlook led the Board to evaluate the proposed project with a relatively conservative price forecast for the products which, however, also showed the project to be economically viable. The Board therefore believes that in the short to medium-term, relatively cheap fuel and feedstock and Dow's international marketing expertise will prove to be more important in assuring the project's success than market conditions.

5.7 ENVIRONMENTAL IMPACT

Views of Dow

In response to questions by Alberta Environment staff, Dow stated that total continuous stack emissions from the expanded plant would be some 25 per cent by weight greater than from the existing plant. This estimate was based on a calculated waste vent gas flow from a plant with approximately 50 per cent greater EDC/VCM production capacity. The potential for fugitive emissions would increase by a few percentage points.

In its plant design, Dow has used a large volume facility with single trains, which minimize the number of equipment pieces, pipelines, valves, etc. and consequently reduce the number of potential leak sources. Dow noted that in the two years operation of the existing plant, fugitive emissions were not a chronic problem, and that the proposed expansion would also use best practical technology for controlling fugitive emissions. The expanded plant is not expected to have a potential for increase in sources for emissions due to factors beyond Dow's control, but because the plant is larger the amount of emissions could be larger.

The sampling of stack emissions once every eight hours would continue as a minimum, and a continuous monitoring system, now being installed for vinyl chloride emissions from existing stacks, would also be installed on the incinerator planned for the EDC/VCM expansion. Over 99.9 per cent combustion efficiency of vinyl chloride monomer in the flare system is expected when the flare is operating smokelessly.

For occupational health reasons, ambient concentrations of vinyl chloride and ethylene on the plant site and around its perimeter are continuously analysed and assessed, and Dow would, if necessary, enlarge this

monitoring system. Hydrogen chloride emissions are presently monitored on a "spot" or "grab" type basis, and this practice would be continued since no reliable continuous monitors have, to Dow's knowledge, been developed for hydrogen chloride. All storm water runoff would, as now, be collected and monitored prior to discharge.

Views of the Board

The Board notes that operation of the proposed plant expansions will require approval by Alberta Environment, but has some concern about potential health hazards from the plant emissions. The Board therefore urges Dow to establish a continuous monitoring system in consultation with Alberta Environment that will maintain appropriate surveillance over the effective operation of the expanded plants. In the Board's view, only such a system, and free access by all interested parties to the data obtained by it, would enable prompt remedial action, where required, to ensure satisfactory operation. The monitoring system would also allay anxieties that have been expressed by local residents and the public media.

APPENDIX A FORM OF PERMIT

IN THE MATTER of the Oil and Gas Conservation Act, being chapter 0-5 of the Revised Statutes of Alberta, 1980; and

IN THE MATTER of an industrial development permit to Dow Chemical Canada Inc. authorizing the use within Alberta of gas produced in Alberta in the production of chlorine and caustic soda

INDUSTRIAL DEVELOPMENT PERMIT NO. DCC 82-2

WHEREAS Dow Chemical Canada Inc. is the holder of Industrial Development Permit No. DCC 80-7 authorizing the use within Alberta of gas produced in Alberta in the production of chlorine and caustic soda; and

WHEREAS Dow Chemical Canada Inc. has applied to the Energy Resources Conservation Board, pursuant to section 30 of the Oil and Gas Conservation Act, to amend Permit No. DCC 80-7; and

WHEREAS the Board upon inquiry into the application, is of the opinion that the granting of the applied for amendments is in the public interest having regard to, among other considerations, the efficient use without waste of energy resources and the present and future availability of hydrocarbons in Alberta; and

WHEREAS the Board considers it proper and desirable to revise and consolidate the permit and to issue a new permit in place of Permit No. DCC 80-7; and

WHEREAS the Lieutenant Governor in Council, by Order in Council numbered and dated , has authorized the granting of the permit.

THEREFORE, the Energy Resources Conservation Board, pursuant to the provisions of section 30 of the Oil and Gas Conservation Act, being chapter O-5 of the Revised Statutes of Alberta, 1980, hereby grants an industrial development permit to Dow Chemical Canada Inc. (hereinafter called "the Permittee") authorizing the use of gas as fuel in the production of chlorine and caustic soda, subject to the regulations and orders made pursuant to the said Act and to the terms and conditions prescribed in this permit as follows:

1. The plant facilities at which chlorine and caustic soda will be produced shall be located on River Lots numbered 1 and 3 of the Fort Saskatchewan Settlement and parts of Sections 2 and 11, both in Township 55, Range 22, West of the 4th Meridian.

2. The quantity of gas that may be used as fuel in the facilities referred to herein in the production of chlorine and caustic soda shall not exceed 359 400 000 cubic metres per calendar year.

3. The quantities of gas for the purpose of this permit shall be on the basis of a gas having a gross heating value of 37.4 megajoules per cubic metre.

4. This permit is for the use by the Permittee of gas as fuel in the production of approximately 549 500 tonnes per year of chlorine and approximately 549 500 tonnes per year of caustic soda, generally as described in the application dated January 16, 1981.

5. All gas used in producing chlorine and caustic soda pursuant to this permit shall be measured by or on behalf of the Permittee in a manner satisfactory to the Board, and the volumes of gas used and chlorine and caustic soda produced shall be separately reported to the Board in a manner satisfactory to the Board.

6. The Permittee shall obtain the approval of the Board of any major changes in design of the plant facilities.

7. (1) The Permittee shall satisfy the Board prior to , as to the arrangements that have been made for the supply of energy resources for the operation of its chlorine and caustic soda plant, unless upon application by the Permittee a later date is stipulated by the Board.

(2) The Permittee shall satisfy the Board prior to , that construction of its proposed expansion project has commenced or will commence on or before , and that construction of the proposed facilities will continue in accordance with a schedule approved by the Board, unless upon application by the Permittee, later dates are stipulated by the Board.

8. The Permitee shall operate the facilities in a manner that results in

(a) the maximum practicably obtainable efficiency in the use of gas for the manufacture of chlorine and caustic soda, and

(b) the maximum practical conservation of gas.

9. The Permittee shall not

(a) assign this permit, or

(b) release from his control the operation of the plant,

without consent in writing of the Board, which may, with the authorization of the Lieutenant Governor in Council, be given by the Board upon application therefor.

10. (1) Attached hereto as Appendix A and made part of this permit is the order of the Lieutenant Governor in Council authorizing the granting of the permit.

(2) This permit is subject to the terms and conditions, if any, prescribed by the order of the Lieutenant Governor in Council set out in Appendix A.

11. Where it appears to the Board or the Lieutenant Governor in Council that the Permittee has contravened or failed to comply with any terms or conditions contained in this permit or any relevant statutes or regulations of Alberta,

(a) the Board shall review the permit and with the approval of the Lieutenant Governor in Council

may cancel the said permit or take such other remedial measures as considered suitable by the Board and the Lieutenant Governor in Council in the circumstances, or

(b) the Lieutenant Governor in Council may amend, vary, add to or replace any terms or conditions contained in this permit.

12. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulations, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

13. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be for a term commencing on the date hereof and ending on December 31, 2004.

14. Permit No. DCC 80-7 is rescinded.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

N. Berkowitz
Vice Chairman

APPENDIX B FORM OF PERMIT

IN THE MATTER of the Oil and Gas Conservation Act, being chapter O-5 of the Revised Statutes of Alberta, 1980; and

IN THE MATTER of an industrial development permit to Dow Chemical Canada Inc. authorizing the use within Alberta of gas and ethylene produced in Alberta in the production of ethylene dichloride and vinyl chloride monomer

INDUSTRIAL DEVELOPMENT PERMIT NO. DCC 82-3

WHEREAS Dow Chemical Canada Inc. is the holder of Industrial Development Permit No. DCC 80-5 authorizing the use within Alberta of gas and ethylene produced in Alberta in the production of ethylene dichloride and vinyl chloride monomer; and

WHEREAS Dow Chemical Canada Inc. has applied to the Energy Resources Conservation Board, pursuant to section 30 of the Oil and Gas Conservation Act, to amend Permit No. DCC 80-5; and

WHEREAS the Board upon inquiry into the application, is of the opinion that the granting of the applied for amendments is in the public interest having regard to, among other considerations, the efficient use without waste of energy resources and the present and future availability of hydrocarbons in Alberta; and

WHEREAS the Board considers it proper and desirable to revise and consolidate the permit and to issue a new permit in place of Permit No. DCC 80-5; and

WHEREAS the Lieutenant Governor in Council, by Order in Council numbered and dated , has authorized the granting of the permit.

THEREFORE, the Energy Resources Conservation Board, pursuant to the provisions of section 30 of the Oil and Gas Conservation Act, being chapter 0-5 of the Revised Statutes of Alberta, 1980, hereby grants an industrial development permit to Dow Chemical Canada Inc. (hereinafter called "the Permittee") authorizing the use of gas as fuel and ethylene as raw material in the production of ethylene dichloride and vinyl chloride monomer, subject to the regulations and orders made pursuant to the said Act and to the terms and conditions prescribed in this permit as follows:

1. The plant facilities at which ethylene dichloride and vinyl chloride monomer will be produced shall be located on River Lots numbered 1 and 3 of the Fort Saskatchewan Settlement and parts of Sections 2 and 11, both in Township 55, Range 22, West of the 4th Meridian.

2. The quantity of energy resources that may be used per calendar year in the facilities referred to herein shall not exceed

(a) 105 000 000 cubic metres of gas as fuel, and

(b) 353 000 tonnes of ethylene as raw material.

3. The quantities of gas for the purpose of this permit shall be on the basis of a gas having a gross heating value of 37.4 megajoules per cubic metre.

4. (1) This permit is for the use by the Permittee of gas and ethylene in the production of approximately 530 000 tonnes of ethylene dichloride and 420 000 tonnes of vinyl chloride monomer per year, generally as described in the application dated January 16, 1981.

(2) Notwithstanding subsection 4(1) the Permittee may vary the relative proportions of the two products in response to market demands, provided that the total annual volumes of gas used as fuel and ethylene used as raw material do not exceed those set out in section 2.

5. All gas used in producing ethylene dichloride and vinyl chloride monomer pursuant to this permit shall be measured by or on behalf of the Permittee in a manner satisfactory to the Board, and the volumes of gas used and ethylene dichloride and vinyl chloride monomer produced shall be separately reported to the Board in a manner satisfactory to the Board.

6. The Permittee shall obtain the approval of the Board of any major changes in design of the plant facilities.

7. (1) The Permittee shall satisfy the Board prior to , as to the arrangements that have been made for the supply of energy resources for the operation of its ethylene dichloride and vinyl chloride monomer plant, unless upon application by the Permittee a later date is stipulated by the Board.

(2) The Permittee shall satisfy the Board prior to , that construction of its proposed expansion project has commenced or will commence on or before , and that construction of the proposed facilities will continue in accordance with a schedule approved by the Board, unless upon application by the Permittee, later dates are stipulated by the Board.

8. The Permitee shall operate the facilities in a manner that results in

(a) the maximum practicably obtainable efficiency in the use of gas and ethylene for the manufacture of ethylene dichloride and vinyl chloride monomer, and

(b) the maximum practical conservation of gas and ethylene.

9. The Permittee shall not

(a) assign this permit, or

(b) release from his control the operation of the plant,

without consent in writing of the Board, which may, with the authorization of the Lieutenant Governor in Council, be given by the Board upon application therefor.

10. (1) Attached hereto as Appendix A and made part of this permit is the order of the Lieutenant Governor in Council authorizing the granting of the permit.

(2) This permit is subject to the terms and conditions, if any, prescribed by the order of the Lieutenant Governor in Council set out in Appendix A.

11. Where it appears to the Board or the Lieutenant Governor in Council that the Permittee has contravened or failed to comply with any terms or conditions contained in this permit or any relevant statutes or regulations of Alberta,

(a) the Board shall review the permit and with the approval of the Lieutenant Governor in Council may cancel the said permit or take such other remedial measures as considered suitable by the Board and the Lieutenant Governor in Council in the circumstances, or

(b) the Lieutenant Governor in Council may amend, vary, add to or replace any terms or conditions contained in this permit.

12. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulations, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas or ethylene within the Province.

13. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be for a term ending on December 31, 2004.

14. Permit No. DCC 80-5 is rescinded.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

N. Berkowitz
Vice Chairman

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATIONS BY ALBERTA ENERGY COMPANY LTD.
FOR PERMITS TO CONSTRUCT OIL PIPELINES
IN THE NORTHEAST EDMONTON AREA

Decision 82-6
Applications 811007
and 811008

1 INTRODUCTION

The Board received two applications pursuant to The Pipeline Act, 1975, for pipelines extending from the East Edmonton refinery area northeasterly to the Aikenside area. The applications were for pipelines to transport crude-bitumen blend to the Edmonton refining area, and bitumen blend diluent (condensate) northward. They form portions of a major pipeline system to transport crude-bitumen blend from the Cold Lake area to Edmonton.

Two previous proceedings of the Board dealt with other sections of the pipeline system, and the Board has separately approved two sections of the pipeline system between Cold Lake and Aikenside. These proceedings and the resultant Board decisions are reported in Board Decision Report 81-7 which details the Board's reasons for approving the Cold Lake-Skaro section, and Decision Report 81-19 which outlines the Board's position regarding the Skaro-Aikenside section. These previous reports also dealt with the need for the pipelines.

Subsequent to those two hearings, the Lieutenant Governor in Council requested that the Board convene an inquiry and report on a suitable pipeline corridor between the existing Restricted Development Area, north of the CN Cloverbar marshalling yards, and the Aikenside area (section 31, township 53, range 22, west of the 4th meridian). The Board held an inquiry in Edmonton during September 1981, and subsequently recommended a corridor to the Government in Inquiry Report 81-29. The Government has since announced that the recommended corridor is accepted and will be declared a Restricted Development Area.

The AEC applications considered in this report by the Board extend through the pipeline corridor between Aikenside and the CN Cloverbar marshalling yards, and south to the refinery area through the existing Sherwood Park RDA (Figure 1). The proposed diluent pipeline is 168.3 mm OD, the blend pipeline is 323.9 mm OD, and both pipelines are approximately 13 km in length.

2 THE HEARING

A public hearing to consider the applications was held in Edmonton on 19 January 1982, with G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and

C. J. Goodman, P.Eng., sitting. Those who appeared at the hearing are shown in the Appendix.

At the hearing, a letter from Alberta Environment was filed in accordance with section 26 of the Board's Rules of Practice. It included a press release from the Hon. Mr. Cookson, Minister of the Environment, stating that the corridor as recommended by the Board would be designated as a Restricted Development Area.

3 VIEWS OF THE PARTICIPANTS

3.1 The Applicant's Views

It was AEC's submission that there were no outstanding issues in connection with the route or the need for the pipelines. AEC contended that the route was pre-determined by the location of the respective pipeline corridors, and that the necessity of the pipeline had been established during the initial hearing of January 1981.

Certain portions of the pipelines would be placed under highways and the CN Cloverbar marshalling yards, and AEC presented details of the pipeline design within the necessary tunnels. The general plan was to install a number of pipelines (carrier pipes) each within its own steel casing, with all casings placed within a 4-foot diameter reinforced concrete tunnel.

Under questioning from CN, AEC agreed to be the principal contact between the pipeline companies and CN with regard to the proposed tunnel. It further stated that it could comply with all of the conditions of crossing suggested by CN.

AEC was questioned regarding imposed loads from the railways, and indicated that it had analysed the design with respect to such additional loads and found the design to be suitable. AEC also said pipeline anchors would not be required at locations adjacent to field bends and tunnels, and it was the company's opinion that temperature changes would not pose any significant problem.

On the subject of co-ordinated corridor design and management, AEC stated that its design was compatible with future corridor uses. AEC plans to use a 5-metre wide easement bordering the eastern and southern limits of the corridor, and its pipelines would be placed in a common ditch located approximately at the centre of the easement. Under questioning, AEC indicated that it had little concern about future operators working over the company's pressurized pipelines, but did however, request that the Board allow 5 metres between its pipelines and the next (future) pipeline.

With respect to AEC's plan for crossing the Genstar property, AEC, upon a request from Genstar, agreed to further extend the highway tunnel to

allow a possible expansion of building facilities on the property. AEC asserted that it was not opposed, subject to a detailed engineering review, to possible extension of plant facilities over the tunnel area.

The applicant also emphasized the close timing under which it was operating, and indicated that some production in the Cold Lake area could be shut in if the pipeline did not become operational on 15 April 1982. The company has contractual commitments to move product at that time, and emphasized that the tunneling procedure could best be accomplished during the fall or winter when ground water conditions are favourable.

The applicant indicated, in response to a concern raised by certain interveners, that it was sympathetic to the view that the Government should acquire ownership of the entire 400-foot proposed corridor as soon as possible. However, it stated that as an applicant for two pipelines, it was not in a position to purchase the full corridor.

3.2 The Interveners' Views

CN Rail did not oppose the application but was concerned that the crossings under its tracks should not disrupt rail traffic. A number of conditions were outlined in its submission, together with a suggestion that from CN's point of view, easier crossings could be made east or west of the proposed tunnel crossing locations. This latter item was not pursued at the hearing.

Genstar objected to the proposed pipeline corridor running diagonally across the east corner of its property, claiming that such a corridor would eliminate the planned upgrading and expansion of its existing plant. It argued that as a result, the present plant facilities would become obsolete and non-competitive, and its future plans to serve the gypsum wallboard market would be hindered.

As part of its submission, Genstar suggested four alternative routes to avoid interference with its property. During the course of the hearing the viability of three of these routes was seriously questioned and virtually eliminated. The fourth, an extension of the pipeline tunnel under Genstar's property at sufficient depth to allow plant expansion, was tentatively accepted by AEC and Genstar subject to final design considerations.

In their submission, the Jacksons contended that the application should be postponed because the corridor was not yet established by Order-in-Council, and in any case, the proposed pipelines should be located adjacent to the Jacksons' property line (the west side of the corridor) instead of 350-400 feet inside their property. They also claimed that AEC's application lacked sufficient design detail to enable a proper assessment of impact on their land.

Tillie Kurysh, represented by Mr. Snaychuk, did not present evidence at the hearing and did not oppose the application.

NUL stated that it was in the process of applying for a permit for a high pressure gas pipeline along part of AEC's proposed route, and that it supported the application of AEC as submitted.

NOVA did not submit evidence, but supported AEC's application. In advancing its argument, NOVA expressed reservations about the future management of the corridor and the possibility of operational and maintenance problems that might arise with the large number of lines to be eventually located in the corridor.

Shell stated that it would also be applying for a permit to construct a pipeline on a routing similar to that of AEC's, and was negotiating with the latter to occupy space within the proposed pipeline tunnels. It fully supported all aspects of AEC's application.

Turbo advised the Board that because its lands were not being adversely affected by the applicant's proposed route, it supported the application.

In written intervention, Mr. Grape, counsel for Johannes Prinz von Thurn und Taxis took the position that AEC's application was premature until the pipeline corridor as recommended in the Board's Inquiry Report 81-29 was ratified by Order-in-Council. As a consequence, Mr. Grape contended that the hearing should be adjourned sine die until a decision had been rendered by the Cabinet, and time allotted for study of the decision. Mr. Grape said at the hearing that when he learned of the Minister's announcement regarding acceptance of the Board's recommendation respecting the corridor, his objection on behalf of his client was no longer valid, and he was therefore not contesting AEC's application.

Mr. Ingram, counsel for Van Heckes et al, stated that because his clients had only received notice of hearing one week earlier, and that he had only been retained as counsel the previous day, he was requesting an adjournment of the proceedings. After his motion was denied, he proceeded to outline his clients' objection to the application, asking that the latter be denied or that a decision be deferred.

Mr. Ingram stated that when land was incorporated into a Restricted Development Area, its value decreased substantially. It was unfair to his clients to negotiate pipeline easements in the corridor after land values had dropped, and he was therefore asking that the entire corridor be purchased by either the Government or a pipeline consortium at present-day assessed values regardless of the impending Restricted Development Area declaration. In this way, his clients would not suffer financial loss, and would receive the same compensation as for adjacent land. As Mr. Ingram explained, this was his reason for requesting a denial or delay of the application... to wait until the corridor lands had been purchased in total.

In answer to Mr. Ingram's concerns, counsel for AEC stated that it would pay full market value for any easements or right of way purchased in the corridor, and that the declaration of the corridor as a Restricted Development Area would in no way lower the land values for purposes of its negotiation with the various landowners.

4 VIEWS OF THE BOARD

The Board has the following views respecting the various matters raised at the hearing.

With respect to CN's suggestion that crossing under its tracks would be better on the section lines east or west of the proposed location, the Board believes the section line locations would not provide a viable corridor, and that it would be inconsistent with the corridor concept to divert the pipelines out of the corridor (and the Restricted Development Area) in order to cross the railway facilities.

Concerning the problem expressed in Genstar's intervention, the Board notes the mutual agreement reached during the hearing between AEC and Genstar to extend the pipeline tunnel underneath Genstar's property. In the Board's view, with proper design considerations given to building expansion over the tunnel as well as to the tunnel, Genstar's concerns can be met.

The Board is sympathetic to the Jacksons' problem of pipelines located some 350 feet inside their property, but believes that the placement of the initial pipelines relative to the corridor boundaries (south and east, also see detail on Figure 1) are in the best general interests of landowners and corridor users. It is important from the standpoint of construction and safety that there be as few pipeline crossovers as possible within the corridor, and this can only be achieved if the initial and subsequent pipelines are parallel throughout, and do not cross one another at turning points. Unfortunately there will be areas along the corridor route such as the Jacksons' property, where the first pipelines to be placed will be farthest from the property line but, since all lines will be buried, there should be minimum interruption of farming operations. The Board recommends that AEC review its pipeline design through any areas similar to and including the Jacksons' property to ensure that any above-ground appurtenances such as valves are located adjacent to existing fence lines or roads.

The concerns expressed by NOVA about the potential administrative problems within the corridor can, in the opinion of the Board, best be handled by a consortium of the operating companies involved. There will undoubtably be a number of mutual operating and maintenance problems to be solved, and the Board believes this to be the best way of dealing with them.

In the case of Van Heckes et al, the Board notes the commitment of AEC to negotiate its easements in the corridor at full market value for the land, and not be influenced in any way by the Restricted Development Area declaration.

With respect to the broader questions raised by Mr. Ingram respecting immediate purchase of the full corridor width, the Board expressed its views, in part, in Inquiry Report 81-29 as follows:

> "The Board believes that acquisition of the total corridor at the outset would be appropriate and in particular fair to current landowners".

The Board continues to have these views and recognizes the concerns of the landowners at the present time. However, it has no jurisdiction in the matter and cannot rule on the situation. It does, however, intend to draw to the attention of the Government, the evidence it received in this respect.

On the matter of technical issues, the Board believes that certain aspects of pipeline design in the tunnel require further review, notably the prevention of casing and pipe corrosion that may develop due to cyclic flooding of the tunnel with fluctuating groundwater levels. The Board recommends that the details concerning end-seal reliability and packing of annular spaces be reviewed with the Board's Pipeline Department engineers before final implementation.

5 DECISION

The Board approves Applications 811007 and 811008 of Alberta Energy Company Ltd. for the route of its proposed pipelines from Lsd 2-31-53-22 W4M to Lsd 8-5-53-23 W4M.

The Board will request the approval of the Minister of the Environment and his consent respecting the use of a Restricted Development Area. If received, the appropriate permits to construct the approved portions of lines will be issued to Alberta Energy Company Ltd.

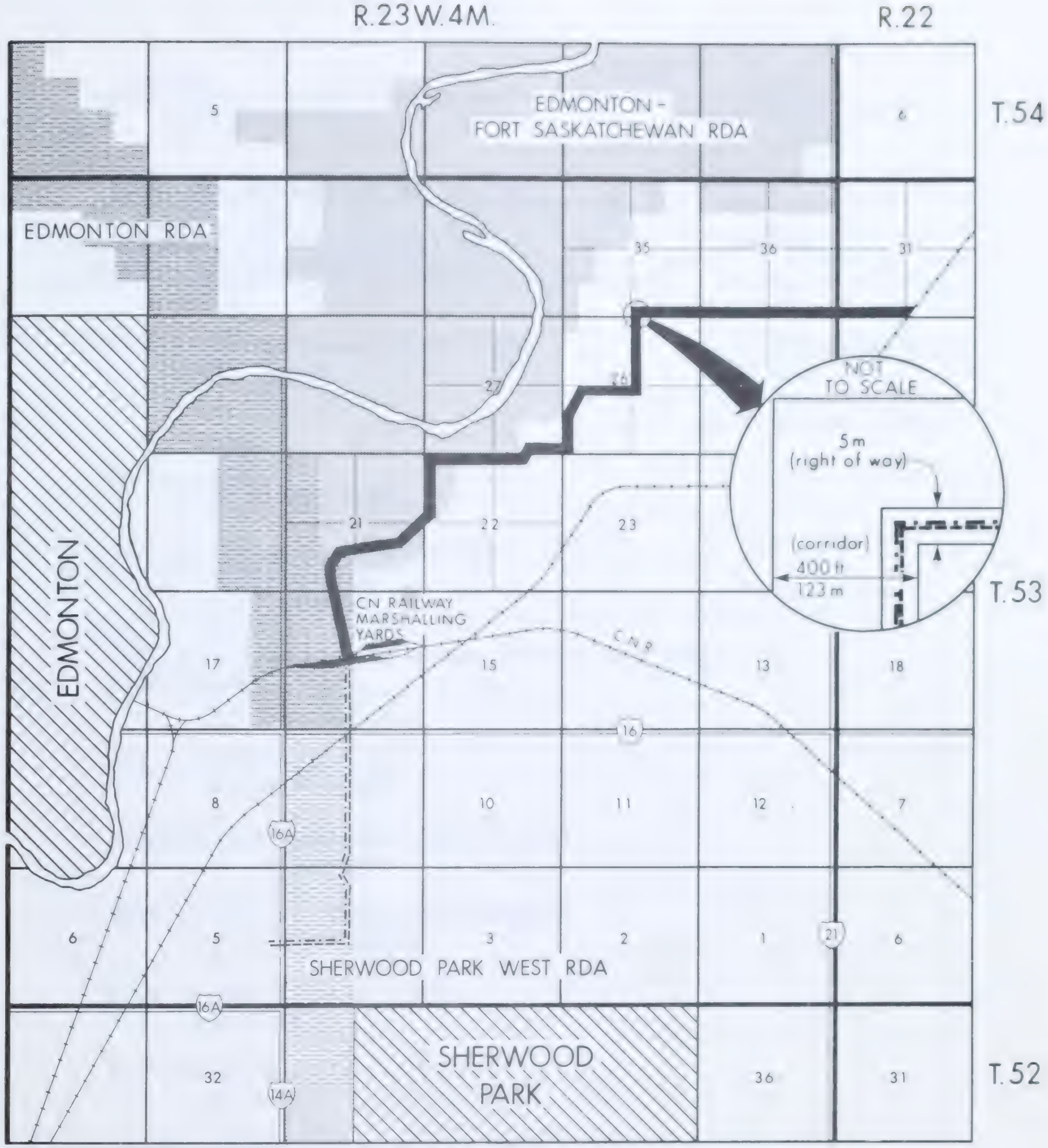
With respect to the design of pipelines in the tunnel, the Board will require the applicant to discuss the final technical design details with the Board's Pipeline Department engineers.

Issued at Calgary, Alberta, on 2 February 1982.

ENERGY RESOURCES CONSERVATION BOARD

GJDeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman



CORRIDOR RECOMMENDED IN ERCB DECISION 81-29

-.-.-.- AEC APPLICATION NO. 811007 (CONDENSATE)

------- AEC APPLICATION NO. 811008 (CRUDE-BITUMEN BLEND)

BOTH PIPELINES TRAVERSE THE ENTIRE LENGTH OF THE RECOMMENDED CORRIDOR

FIGURE 1 PROPOSED ROUTE THROUGH THE EAST EDMONTON AREA

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

APPENDIX

THOSE WHO APPEARED AT THE HEARING

Principal and Representatives (Abbreviations used in Report)	Witnesses
Alberta Energy Company Ltd. (AEC)	J. E. Ellefson, P.Eng.
D. Thomas	D. Henley
	J. H. Russell, P.Eng.
	R. A. Nemeth, P.Eng.
CN Rail (CN)	
J. Kerby, P.Eng.	
Genstar Gypsum Limited (Genstar)	
E. L. Bunnell	
M. J. Burch	
Donald F. and Helen Catherine Jackson (the Jacksons)	
H. Schroeder	
E. Walter	
Mrs. T. Kurysh	
L. M. Snaychuk	
Northwestern Utilities Limited (NUL)	
B. Zalmanowitz	
NOVA, An Alberta Corporation (NOVA)	
H. D. Williamson	
Shell Canada Limited (Shell)	
R. Curtis	
Turbo Resources Limited (Turbo)	
G. Libel	
Johannes Prinz von Thurn und Taxis	
I. F. Grape	
Clara and Arthur Van Hecke (Van Heckes et al)	
Albert Komant	
Alaskan Holdings Limited	
D. J. Ingram	
Energy Resources Conservation Board staff (Board staff)	
M. J. Bruni	
R. J. Allman, P.Eng.	
G. C. Dunn, P.Eng.	

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
PERMIT TO CONSTRUCT A PIPELINE
OKOTOKS TO CAYLEY

Decision 82-7
Application 810465

1 INTRODUCTION

1.1 The Application

Canadian Western Natural Gas Company Limited (CWNG) applied to the Energy Resources Conservation Board (Board), pursuant to The Pipeline Act, 1975[1], for a permit to construct approximately 35 kilometres (km) of 323.9 millimetre (mm) outside diameter (OD) pipeline, 0.02 km of 114.3 mm OD pipeline, and 0.15 km of 219.1 mm OD pipeline from legal subdivision 15, section 20, township 17, range 28, west of the 4th meridian to Lsd 16-21-20-29 W4M.

The proposed pipeline route is shown on Figure 1.

The application also includes three alternative routes (A-1, A-2, A-3) in the area around High River, as shown on Figure 2.

1.2 The Hearing

The application was considered at a public hearing on 8 December 1981 in High River, Alberta, with V. E. Bohme, P.Eng., C. J. Goodman, P.Eng., and E. J. Morin, P.Eng., sitting. Those who appeared at the hearing are shown in the following table. G. F. Noble and the Prudential Insurance Company of America filed written submissions with the Board but did not appear at the hearing.

1.3 The Issues

The Board considers the issues to be:

- The need for the pipeline
- Pipeline design and proposed operation
- Route selection

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1 Now renamed the Pipeline Act (chapter P-8, RSA 1980).

THOSE WHO APPEARED AT THE HEARING

Principal and Representatives (Abbreviations used in Report)	Witnesses
Canadian Western Natural Gas Company Limited (CWNG) G. N. McDermid	J. H. Parkinson, P.Eng. D. Tse, P.Eng. E. Porter, P.Eng. W. D. Cascadden
Town of High River (Town) C. Dean	C. Dean
F. Wolfe, R. F. Jennings, and Snider Dahow Holdings Ltd. (Wolfe group) R. M. Wilkinson	
P. Robertson B. V. Reed, Q.C. (Sask.)	P. Robertson
W. Fuhrman (Fuhrman group) H. Fuhrman R. Aitken Goldwind Farms Ltd. B. Fossen E. Fossen R. Clark N. Clark S. Hock J. Hock W. Borger E. Borger J. G. Coy B. Coy I. Dudgeon N. P. Dudgeon P. K. Matkin	W. Fuhrman W. Borger J. G. Coy I. Dudgeon
B. Ellis	B. Ellis
Energy Resources Conservation Board staff C. J. C. Page H. W. Knox, P.Eng. G. J. Vogt	

2 PRELIMINARY MATTERS

At the beginning of the hearing, Mr. Ellis, an owner of land on the proposed route, indicated to the Board that he had signed an easement for CWNG to cross his property before he was aware of the Board hearing regarding the proposed pipeline. Mr. Ellis therefore asked if the hearing was not being held after the fact.

Mr. Ellis was advised that it was the usual practice for companies to obtain easements if possible before applying to the Board for a permit, and that the signing of an easement would not necessarily bar a landowner from intervening at a hearing. Mr. Ellis made no further representations.

3 THE NEED FOR THE PIPELINE

3.1 Views of the Applicant

The applicant stated that the proposed pipeline between Okotoks and Cayley is part of a program to replace its existing main-line from the southern outskirts of Calgary to the NOVA-CWNG interchange near Monarch, Alberta. CWNG claimed that the need for the replacement was to provide a safer operating pipeline and to improve the integrity of the system supply.

CWNG indicated that the existing main-line pipe was installed in 1912, and a number of operational problems had developed due to its lengthy period in service. The depth of cover of the existing line along the route had decreased due to erosion, exposing some segments of the line. CWNG stressed its concern over a possible rupture of the existing line from third-party damage. Metallurgical analysis showed that the pipe had some ductility, hence very low resistance to impact loading, at normal temperatures.

CWNG also said that the existing pipe has mechanical compression couplings, and no external coating. Providing cathodic protection to present day standards was too difficult and expensive. As a result, leaks had occurred due to corrosion and joint-seal deterioration.

CWNG also stated its concern about the increasing population density along the existing line due to urban encroachment. As an example, CWNG observed that the line passes through High River, a situation which is undesirable by present standards for the location of a high pressure pipeline.

3.2 Views of the Interveners

The interveners did not question the need to replace the existing pipeline.

3.3 Views of the Board

The Board is of the view that the need for the new pipeline has been adequately established, and that replacement is necessary to ensure a safer pipeline and improved security for the supply of gas.

4 PIPELINE DESIGN AND PROPOSED OPERATION

4.1 Views of the Applicant

CWNG stated that the proposed pipeline and all valves, flanges and fittings had been designed to meet or exceed minimum criteria in accordance with Canadian Standards Association Standard Z184-M1979, Gas Pipeline Systems, and pertinent Energy Resources Conservation Board Interim Directives.

CWNG also indicated that the pipeline would be designed to Class 2[2] location criteria, which would provide for commercial or light industrial development adjacent to the pipeline right of way. In addition, CWNG stated that its policy was to recommend to appropriate municipal authorities that a 15 metre (m) building setback be required for any buildings on either side of the pipeline. CWNG planned to utilize increased burial depths at all road and railway crossings. An annual leak-detection program would be carried out, along with regular maintenance inspections. CWNG stated that if a permit was granted for the proposed pipeline, the company would utilize the existing line passing

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2 The class location unit is an area that extends 200 m on either side of the centreline of any continuous 1.6 km length of pipeline.

Class 2 location is:

(a) Any class location unit that has more than 10 but fewer than 46 dwelling units intended for human occupancy; or

(b) An area where the pipeline lies within 90 m of any of the following:

(i) A building that is occupied by 20 or more persons during normal use;

(ii) A small, well-defined outside area that is occupied by 20 or more persons during normal use, such as a playground, recreation area, outdoor theatre, or other places of public assembly.

through High River as a low-pressure distribution pipeline. If necessary, CWNG would replace the line later, but believed it to be adequate for low-pressure distribution service. Regular maintenance and monitoring would, in any case, indicate if and when the line should be replaced.

4.2 Views of the Board

The Board has considered the overall pipeline design proposed by CWNG, and is satisfied that it complies with the requirements of The Pipeline Act, 1975[1].

The Board believes that the design is adequate, having regard for the intended use of the pipeline, the routes considered, and the type and potential extent of future development indicated by the Town and other interveners. While it considers commercial or industrial development immediately adjacent to the proposed right of way more acceptable than residential development, it believes that the proposed design, and the implementation of a 15 m building setback from the pipeline would be adequate for a considerable time to come. The proposed parallelling of existing linear disturbances such as powerlines or roads would reduce potential building restrictions, and the increased burial depths at road and railway crossings would improve the security of the pipeline.

The Board agrees that the existing portion of pipeline through High River would be adequate for low-pressure distribution service in the short term.

With respect to the new portion of pipeline, the Board notes that CWNG has provided sufficient detail as to its planned operating and maintenance procedures to indicate that the system would be adequately monitored and maintained.

5 ROUTE SELECTION

5.1 Views of the Applicant

CWNG stated that it had evaluated five alternative routes to replace the existing 406 mm pipeline. All the alternatives evaluated from Okotoks to High River parallel the original line, and alternative routes around High River and to Cayley were considered. Figure 3 shows the alternative routes considered and subsequently rejected by CWNG.

The criteria used by CWNG to evaluate the routes were:

- o economics
- o future subdivision development
- o surface damage
- o ecological concerns, and
- o the possibility of parallelling existing utility or transportation rights of way.

Route A

During the proceeding, CWNG amended Route A in one location and decreased the pipeline setback distances in two other locations. The first change involved rerouting the pipeline in the SW 1/4 2-20-29 W4M to follow a route adjacent to the east and north boundaries of the quarter section. CWNG stated that this resulted from negotiations with the Wolfe group during which it was determined that the group had completed plans for a country residential subdivision for that quarter section. With respect to the east-west portion of Route A, immediately north of High River, CWNG decreased the setback from the edge of the road allowance to the edge of its proposed right of way from 39.5 m to 30 m, stating that 30 m was acceptable to the municipal district. In the SW 1/4 4-19-28 W4M, CWNG proposed locating the pipeline 3 m from the eastern edge of its right of way as opposed to the 4.5 m applied for in its application, in order to provide for a 6 m construction spoilbank area on its right of way.

Routes B-E

Route B was rejected because it passed through High River, which would result in a high-pressure facility close to densely populated areas.

Route C was rejected because the additional length of this route would result in increased capital and construction costs. Also, a number of trees west of High River would need to be removed, and several residences would be close to this route.

Route D was rejected for three reasons. Firstly, it would conflict with a potential interchange at the intersection of Highway 2 and the municipal district road to the northeast of High River in the NW 1/4 9-19-28 W4M. Secondly, it would require an additional crossing of Highway 2 to a future regulator station to be located in the SW 1/4 4-19-28 W4M. The station would service the expanding industrial section in that area. Finally, it would impact on a number of farmyards adjacent to Highway 2 between High River and Cayley.

Route E was rejected because it would cross an area currently annexed by the Town of High River.

Alternative Routes A1-A3

CWNG stated that it would accept any of the alternatives, namely A-1, A-2, or A-3, for inclusion with the remainder of Route A (see Figure 2). It indicated that A-1 was preferred because it would have an impact on the least number of landowners, would parallel an existing municipal road allowance and service road, and would avoid the potential interchange at Highway 2 and the municipal district road on the north boundary of section 9-19-28 W4M.

CWNG contended that Route A-1 would not restrict annexation of the W 1/2 9-19-28 W4M should the Town decide to annex lands to the northeast of High River. Additionally, CWNG stated that building restrictions on those lands because of A-1 would be highly unlikely.

Route A-2 in the NW 1/4 9-19-28 W4M would be adjacent to and north of the boundary dividing Blocks 1 and 2 of the country residential subdivision in that quarter. The north-south right of way for A-2 in the W 1/2 9-19-28 W4M would have a 43 m setback from the Highway 2 right of way. CWNG stated that A-2 had the advantage of parallelling the existing highway. Furthermore, it indicated that Alberta Transportation would require a 41 m building restriction setback, over and above the 43 m setback to its proposed right of way, and that this would provide additional security for the pipeline. It stated that A-2 would affect the most landowners since it would pass through a small-acreage subdivision in section 9-19-28 W4M.

The third alternative, A-3, would parallel the exsisting 240 kV transmission line operated by TransAlta Utilities Corporation (TransAlta Ultilities), which traverses section 8-19-28 W4M and the W 1/2 9-19-28 W4M. CWNG indicated that a 30 m separation distance would minimize any induced electromagnetic coupling between the transmission line and the pipeline. It stated that this separation distance could possibly be reduced, depending upon the results of calculations that would be done by TransAlta Utilities when soil resistivity data were obtained for this route. CWNG also pointed out that with a 30 m separation distance, a 12.5 m strip of land would be unavailable for future subdivision. In addition, A-3 would be close to an existing residence in the SW 1/4 9-19-28 W4M.

5.2 Views of the Interveners

The Wolfe Group

The Wolfe group, which originally objected to the diagonal crossing of its lands, withdrew its intervention after CWNG amended its route to follow the north and east sides of the SW 1/4 2-20-29 W4M.

P. Robertson

Mrs. P. Robertson, owner of the NW 1/4 8-19-28 W4M, the S 1/2 8-19-28 W4M, and section 17-19-28 W4M, stated that regardless of the route selected by

CWNG she would be affected by any of the A route alternatives. Mrs. Robertson preferred Route C because it would affect fewer landowners to the northeast of High River and would not directly impact the NW 1/4 8-19-28 W4M, which she contended had good potential for subdivision along the Highwood River. In addition, she stated that Route C would not limit the growth of High River, as those lands to the south and west were within the "one in one hundred year" flood plain and would probably not be annexed by the Town. Mrs. Robertson also indicated that Routes A and D would have similar effects on her lands. She cited potential building restrictions to the NW 1/4 8-19-28 W4M, in particular that portion along the Highwood River, as a possible result of locating the line along either of these two routes.

With respect to Route B, Mrs. Robertson stated that development would be restricted in the S 1/2 17-19-28 W4M, the NW 1/4 8-19-28 W4M, and the SE 1/4 8-19-28 W4M. She claimed that Route E would be less desirable than the others as it would affect section 17-19-28 W4M and SE 1/4 8-19-28 W4M; land she indicated as having good agricultural capabilities.

Route A-1 was unacceptable to Mrs. Robertson because it would traverse the NW 1/4 8-19-28 W4M, in the vicinity of the lands along the Highwood River that she said had high subdivision potential. She also noted that Route A-1 additionally affected the SE 1/4 8-19-28 W4M. She said that in all likelihood all of section 8-19-29 W4M would be annexed by the Town in the near future.

Commenting on Route A-2, Mrs. Robertson said that, while Route A-2 would directly affect the acreage landowners in the W 1/2 9-19-28 W4M, it would have the least impact on her lands.

Mrs. Robertson stated that Route A-3 would have the highest impact on her lands because it would sterilize subdividable lands between CWNG's proposed right of way and TransAlta Utilities' existing right of way, as well as hindering future annexation of section 8-19-28 W4M.

The Fuhrman Group

The Fuhrman group of owners in the W 1/2 9-19-28 W4M and a portion of SE 1/4 16-19-28 W4M, were represented by Mr. W. Fuhrman, Mr. W. Borger, Mr. J. C. Coy, and Mr. I. Dudgeon. The group stated that most of the land in the W 1/2 9-19-28 W4M was presently being utilized for pasture or hay production, although Mr. Borger indicated that he was developing a tree farm on his property. Mr. Borger was of the opinion that the W 1/2 9-19-28 W4M was ideal for future development, whether commercial, industrial, or residential, and Mr. Fuhrman supported Mr. Borger, stating that although he no longer resided on his property, he retained it because of its development potential. With regard to Alternative Route A-1, the group's members claimed that they forsaw potential building restrictions on their properties, as well as the possibility that the value of their lands would be significantly decreased because the Town would view Route A-1 as a barrier to annexation. Additionally, these landowners

indicated that Route A-1 would be too close to their residences, hence would result in a safety hazard.

Mr. Borger and Mr. Coy both stated that Route A-3 would have a direct impact on their properties, with more of CWNG's right of way crossing Mr. Borger's property. Mr. Borger argued that he "would be very concerned about the safety of (his) family" with this alternative route, and that any future development of his property would be restricted.

Of the alternatives evaluated, the group's members preferred Route A-2, but expressed concerns regarding possible building restrictions to their properties. They indicated an understanding that there may be future building restrictions associated with CWNG's proposed 18 m right of way along Route A-2, beyond Alberta Transportation's required 43 m setback, but stated that potential annexation was of more concern to them. The Fuhrman group's representatives informed the Board that they had met with Alberta Transportation regarding the 43 m setback from the existing highway to CWNG's proposed right of way, and Mr. Borger stated that Alberta Transportation had indicated that the building setback of 43 m would be required for future multi-lanes and the widening of Highway 2.

The Town of High River

Mr. C. Dean, manager for the Town, stated that the town council preferred Route A-2 because it saw Routes A-1 and A-3 as barriers to the future annexation of the W 1/2 9-19-28 W4M, and the northeast portion of section 8-19-28 W4M respectively. He indicated that the council believed that a route along the future boundaries of the town would be more acceptable than having such high-pressure pipeline facilities cross through the town.

Having regard for the future growth of the town, Mr. Dean pointed out that the regional planning authorities now require a 20-or 30-year growth plan with any annexation proposals. He stated that the town is projected to grow to a population of 20 000 people in the year 2000, assuming a 7 per cent per annum growth rate. When questioned regarding the area where future annexation would likely take place, Mr. Dean did not identify specific areas but indicated that lands to the west and southwest of the town were not as desirable, since they were located within the "one in one hundred year" flood plain of the Highwood River. He also noted that the lands east of Highway 2 had not been considered for annexation purposes. Mr. Dean indicated that no firm plans regarding annexation would be available until early 1982.

With respect to Route C, Mr. Dean stated that the east-west laterals associated with this route would effectively surround the existing town boundaries, and would cross lands with annexation potential to the north, south, and southeast of High River. He indicated that Route C was

less preferable than Route A (with alternative A-2) because the town council believed that high-pressure facilities were acceptable only on the boundaries of areas having annexation potential.

5.3 Views of the Board

With regard to the intervention of the Wolfe group, the Board notes CWNG's amendment to its application which resulted in the withdrawal of the group's intervention. The Board notes that this alteration would result in a relatively small extra cost, and accepts the route agreed to by CWNG.

With regard to Mrs. Robertson's concerns, the Board notes her preference for Route C, and agrees that Route A could have some effect on development of river front property in the NW 1/4 8-19-28 W4M. Route C would have the advantage of traversing areas to the west of High River that will probably not be annexed by the Town, but the Board agrees with CWNG that somewhat greater environmental damage would occur along that route, and in addition it would pass close to existing residences on the west side of High River. The Board also believes that the northern east-west lateral of Route C would have an adverse effect on any future development that may take place north of the town.

With respect to Mrs. Robertson's concerns regarding possible building restrictions associated with Route A-1 in the NW 1/4 8-19-28 W4M, and the SE 1/4 8-19-28 W4M, the Board agrees that future development on land near this right of way could be restricted from future development (assuming a 15 m building setback from the pipeline) but believes the annexation of section 8-19-28 W4M would not be affected significantly.

The Board agrees that Route A-3 would preclude development of a strip of land between the existing TransAlta Utilities 240 kV transmission line right of way and that proposed by CWNG. The Board notes that this alternative parallels an existing linear disturbance through section 8-19-28 W4M, but believes that in this instance the restriction of future development would be greater than any benefits achieved.

The Board notes that, for the lands owned by the Fuhrman group in the W 1/2 9-19-28 W4M, the group concurred with the Town's view that Routes A-1 and A-3 would hinder annexation of those lands and impose building restrictions in the immediate vicinity of the routes. The Board recognizes that Route A-3 would result in the pipeline being close to Mr. Borger's residence.

With respect to Route A-2, the Board notes that it would avoid the potential interchange of Highway 2 and the municipal district road, but may cause only a potential 3 m building restriction along the northern boundary of Block 2, owned by Mr. Fuhrman, in the NW 1/4 9-19-28 W4M. Although the route would affect a number of landowners, the impact on each would be relatively small. The Board notes the landowners' preference for that portion of Route A-2 adjacent to Highway 2. The Board agrees that parallelling existing facilities in this location would be appropriate.

6 FINDINGS

In summary, the Board believes Route A to be the superior route. The Board is also of the opinion that Route A-2 would be preferable to Routes A-1 or A-3 because it would have the least effect on future development of lands with annexation potential. Also, it is the route preferred by the Fuhrman group, and provides for the future construction of an interchange at the Highway 2 and municipal road intersection. Additionally, Route A-2 would not impact Mrs. Robertson's land in the SE 1/4 8-19-28 W4M as would Route A-1. The Board also accepts that a pipeline route parallel to Highway 2 from north of High River to Cayley would have the advantage of removing a diagonal pipeline across lands south of High River.

7 DECISION

The Board approves Application 810465 of Canadian Western Natural Gas Company Limited, as amended, and including alternative Route A-2 to be used in the vicinity of High River. It will issue a permit in due course.

ISSUED at Calgary, Alberta, on 9 February 1982.

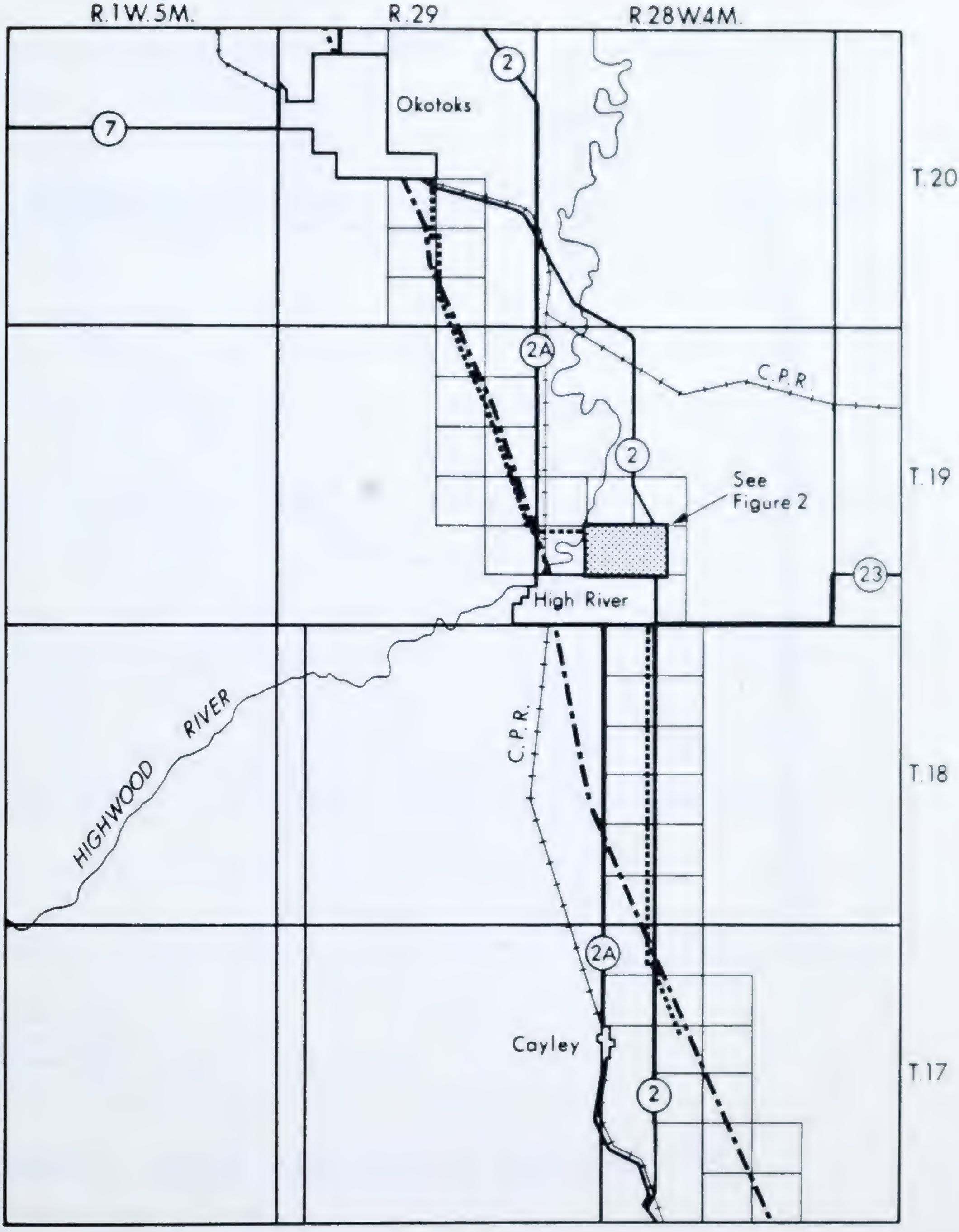
ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme
Board Member

C. J. Goodman

C. J. Goodman
Board Member

E. J. Morin
Acting Board Member



Existing pipeline
Proposed pipeline

FIGURE 1 PROPOSED OKOTOKS TO CAYLEY PIPELINE (ROUTE A)

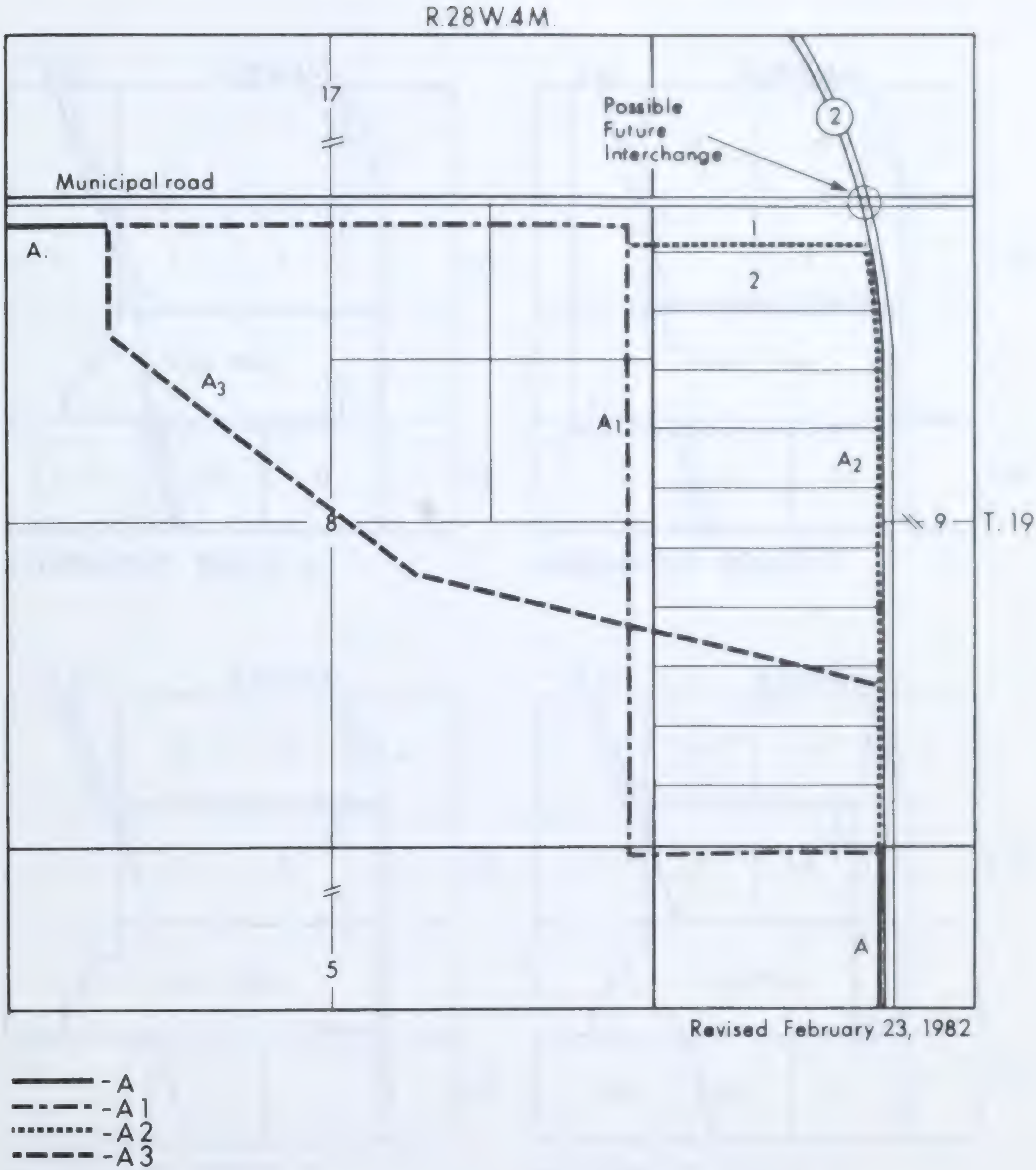
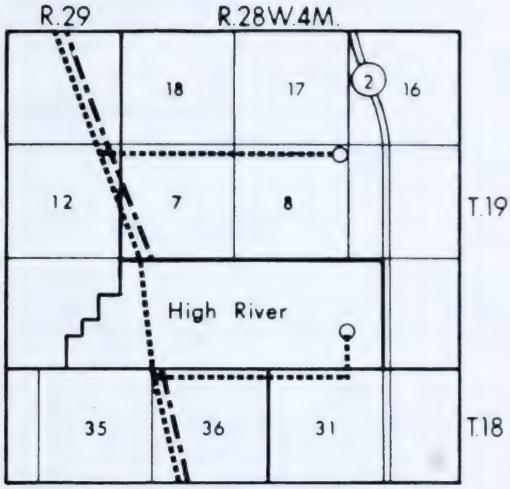
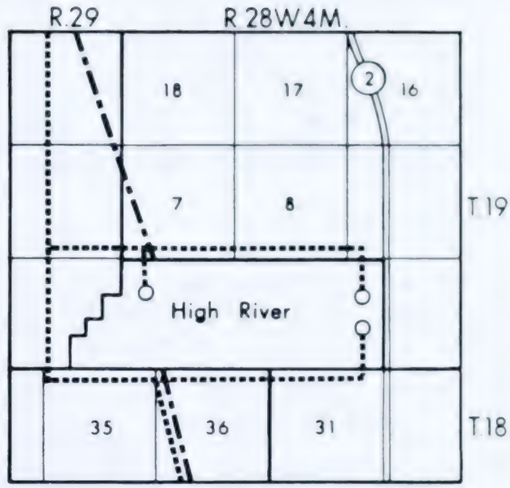


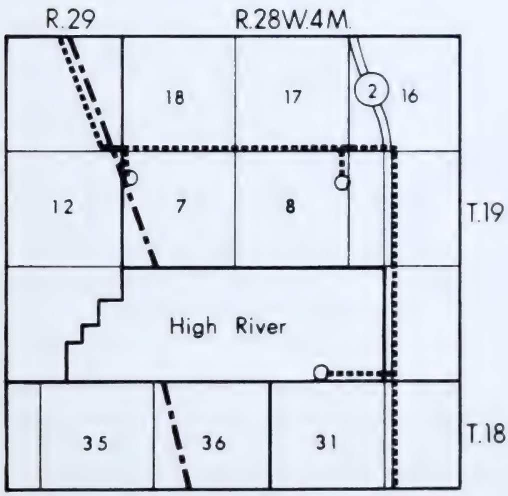
FIGURE 2 PIPELINE ALTERNATIVES IN HIGH RIVER AREA.



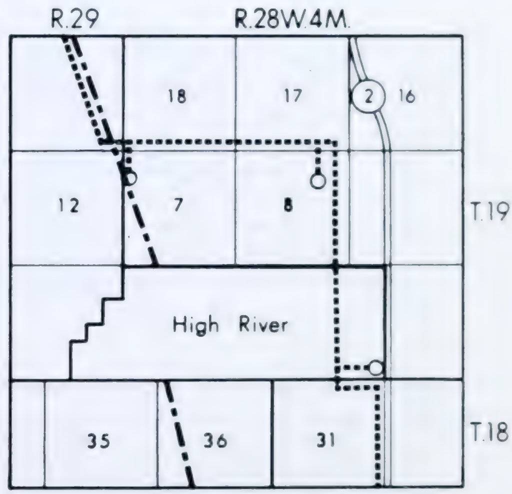
ALTERNATIVE ROUTE B



ALTERNATIVE ROUTE C



ALTERNATIVE ROUTE D



ALTERNATIVE ROUTE E

—·—· Existing pipeline
-------- Proposed pipeline
o Proposed regulator station

FIGURE 3 OTHER ALTERNATIVES CONSIDERED

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

SULPETRO LIMITED
GAS REMOVAL PERMIT APPLICATION

Decision 82-8
Application 810696

1 INTRODUCTION

Sulpetro Limited (Sulpetro) applied to the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act (the Act), for a gas removal permit which would reflect the following:

- an 8-year term from 1 November 1983 to 31 October 1991;
- a total volume of some 4.653×10^9 cubic metres (m^3) of gas;
- a maximum daily volume of 2.125×10^6 m^3;
- a maximum annual volume of some 775.5×10^6 m^3 for the period to 31 October 1987 decreasing thereafter by 20 per cent each year to 155.1×10^6 m^3 during the last year commencing 1 November 1990; and
- the naming of 18 pools, fields, and areas from which gas may be obtained for removal from the province.

Sulpetro is currently removing gas from Alberta under its gas removal Permit No. SC 78-1 which authorizes a total removal of 2.03×10^9 m^3 of gas during the period 3 April 1979 to 31 October 1983. The gas is delivered via the TransCanada PipeLines Limited (TransCanada) facilities to Sulpetro's United States customer, Transcontinental Gas Pipe Line Corporation (Transco), at Niagara Falls, Ontario. In 1980 Sulpetro signed a new gas sales contract with Transco for an 8-year term from 1 November 1983 to 31 October 1991. The contract specifies an annual quantity of 775.5×10^6 m^3 to 31 October 1987, thereafter decreasing by 20 per cent each contract year to an annual quantity of 155.1×10^6 m^3 during the last contract year.

Under a Sulpetro/Pan-Alberta Gas Ltd. (Pan-Alberta) contract, Sulpetro's gas supply currently serving the Transco market reverts to Pan-Alberta on 1 November 1983. Therefore, Sulpetro has developed, for purposes of the subject application, a new gas supply from its own working interest reserves, by contracting with other Alberta gas producers, and through arrangements with TransCanada and Pan-Alberta.

The application was heard by the Board at a public hearing held in Calgary, Alberta on 1 December 1981, with G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and C. J. Goodman, P.Eng., sitting.

Of the four interventions received, only PanCanadian Petroleum Limited's intervention presented evidence. The others were for purposes of cross-examination and argument only.

Participants at the hearing are listed in Table 1-1.

TABLE 1-1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in this Report)	Witnesses
Sulpetro Limited (Sulpetro) S. Carscallen	N. E. Frost D. C. Fonteyne
Alberta and Southern Gas Co. Ltd. T. R. Benson	
PanCanadian Petroleum Limited (PanCanadian) W. J. Hope-Ross	
Texaco Canada Resources W. F. Muscoby	
TransCanada PipeLines Limited (TransCanada) E. W. H. Mallabone	
Energy Resources Conservation Board staff C. J. C. Page H. G. Halladay, C.E.T. V. J. Vogt	

2 ISSUES

The Board considers the following to be the issues relevant to its appraisal of the application:

- inclusion of the Wembley Halfway B Pool as part of Sulpetro's gas supply;
- the reserves under contract to Sulpetro and the volumes available for inclusion in the permit;
- the gas surplus to Alberta's requirements and permit commitments; and
- other conditions of the permit, if one is issued.

3 INCLUSION OF THE WEMBLEY HALFWAY B POOL

Sulpetro included a portion of the Wembley Halfway B pool associated gas cap (gas in contact with an oil pool) as part of its supply. PanCanadian submitted that the gas cap expansion provides the drive mechanism for oil production and that depletion of gas cap pressure would be detrimental to ultimate oil recovery. Therefore, while PanCanadian supported the application in principle, it intervened to ensure that Sulpetro would not be allowed to produce the Wembley Halfway B pool gas cap without first obtaining a concurrent production approval as required under Section 29.(1)[1] of the Oil and Gas Conservation Act, and that such an approval would be the subject of a separate hearing.

Sulpetro submitted that it would be applying for a concurrent production approval in the near future and that the reserves should be included as part of its supply in support of the application.

Since the Wembley Halfway B pool gas cap cannot be produced in the absence of a concurrent production approval which would be the subject of a separate application to the Board and, if appropriate, a separate hearing, and since Sulpetro intends to make such an application, the Board believes that the reserves should be considered as part of Sulpetro's gas supply. If a gas removal permit is granted but approval for concurrent production is denied, and if Sulpetro is unable to otherwise make up for the loss in reserves and deliverability, the Board would likely call a hearing to review the permit. The Board emphasizes that inclusion of the reserves in a gas removal permit will in no way affect the Board's decision on a subsequent application for a concurrent production approval.

4 RESERVES UNDER CONTRACT TO SULPETRO AND THE VOLUMES AVAILABLE FOR INCLUSION IN THE PERMIT

4.1 Views of Sulpetro

Sulpetro's reserve estimates, as shown in its original application, were made as of 30 April 1981 and totalled some 5.47×10^9 m^3 of established reserves under control. At the hearing, Sulpetro submitted revisions to its reserve estimates which reflected additional drilling on Sulpetro's lands to about 30 October 1981 and which increased the reserves under Sulpetro's control to a total of some 6.48×10^9 m^3. This total includes some 1.05×10^9 m^3 of reserves in the Wembley Halfway B pool.

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1 Previously, under the 1970 Revised Statutes of Alberta, this was Section 41.(1) of the Oil and Gas Conservation Act.

Sulpetro also indicated that, under the conditions of contracts it has with both TransCanada and Pan-Alberta, Sulpetro has access to certain additional volumes if they are not required to meet TransCanada or Pan-Alberta markets.

Sulpetro submitted several deliverability schedules which indicated that it could deliver the applied-for volumes from its supply sources with only minor deficiencies under certain scenarios. Sulpetro stated that any indicated supply deficiencies could be avoided by additional drilling on its currently contracted lands and/or by augmenting its supply with volumes available from TransCanada or Pan-Alberta.

4.2 Views of the Board

The Board's estimate of reserves under Sulpetro's control as of 31 December 1981 is some 5.09×10^9 m^3 including some 1.31×10^9 m^3 for the Wembley Halfway B pool. Sulpetro's reserve estimates are higher than the Board's mainly because Sulpetro recognizes a larger areal extent for a few isopached pools and for several one well pools.

The Board believes that the established reserves currently under Sulpetro's control are not capable of delivering the applied-for volumes over the permit term, especially if concurrent production is not approved for the Wembley Halfway B pool or if the production rate is limited for this pool. However, the Board believes there is considerable potential for reserve appreciation on lands under Sulpetro's control, as attested to by recent drilling, and additional volumes may be available to Sulpetro from TransCanada and Pan-Alberta. Therefore, the Board is prepared, provided such volumes are surplus to Alberta's requirements, to grant a permit to Sulpetro for the applied-for 4.653×10^9 m^3. Should Sulpetro be unable to augment its currently established supply as expected, the Board would likely call a hearing to review the permit.

5 GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS

All references to reserves in this section are to marketable gas on a 37.4×10^6 joules per m^3 basis.

5.1 Reserves Test

Sulpetro estimated the reserves surplus as of 31 December 1980 to be 322.3×10^9 m^3. In making this estimate, Sulpetro utilized data published by the Board.

Since the Board has not completed its assessment of the established Alberta gas reserves as of 31 December 1981 and since the applied-for volumes are small, the Board has estimated the reserves surplus as of 31 December 1980. The Board's estimates, which indicate a reserves surplus of 386 x 10^9 m^3, are presented in Table 5-1. They are similar to the estimates presented by Sulpetro. The Board expects that the surplus as of 31 December 1981 would be even larger.

5.2 Deliverability Test

Sulpetro did not submit a deliverability test with its application but relied on the figures presented by the Board in ERCB Report 80-G[2].

In light of the small volumes being applied-for, the large deliverability surplus as indicated in ERCB Report 80-G, and the Board's view that the deliverability surplus has likely grown since the preparation of that report, the Board is satisfied that the applied-for volumes can be delivered without any impact on Alberta's requirements and existing permit commitments. Therefore the Board has not recalculated the deliverability test for purposes of this application.

6 OTHER CONDITIONS OF THE PERMIT

6.1 Permit Term

Sulpetro has applied for an 8-year term from 1 November 1983 to 31 October 1991, a term which corresponds to that of Sulpetro's sales contract to Transco. The Board believes the applied-for term is appropriate.

6.2 Maximum Daily and Annual Volumes

Sulpetro applied for a maximum daily permit volume of 2.125 x 10^6 m^3 for the full permit term and a maximum annual volume of 775.5 x 10^6 m^3 for the period to 31 October 1987, thereafter decreasing by 20 per cent each year ending 31 October to a maximum of 155.1 x 10^6 m^3 during the last year of the permit. These are the volumes specified in Sulpetro's sales contract to Transco. The Board believes the applied-for daily and annual permit maximums are appropriate.

6.3 Permit Pools, Fields, and Areas

Sulpetro's application requested that the permit specify 18 pools, fields and areas from which Sulpetro may obtain gas for removal from the province.

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2 Pan-Alberta Gas Ltd. Gas Removal Permit Amendment Decision. ERCB Report 80-G, October 1980.

TABLE 5-1 GAS RESERVES TEST AS AT 31 DECEMBER 1980
AS ESTIMATED BY THE BOARD
10^9 m^3 at 37.4×10^6 joules per m^3

RESERVES		
1.	Total Remaining Established Reserves	1 814
2.	Less: Beyond Economic Reach	65
3.	Less: Deferred	101
4.	Total Available Reserves	1 648
REQUIREMENTS		
	Alberta Requirements	
5.	General Requirements ($25A_1$)	329
6.	Permit-related fuel and shrinkage	85
	Permit Requirements	
7.	Remaining Permit Commitments	843
8.	Applied-for and Deliverable Volumes	5
9.	Total Requirements	1262
10.	RESERVES SURPLUS	386

In assessing the reserves available to Sulpetro, the Board has designated new fields and revised existing field boundaries. Accordingly the Board is prepared to name 24 pools, fields, and areas in the permit. These pools, fields, and areas, as shown in the form of the permit in the Appendix, are those in which the Board recognizes reserves available to Sulpetro.

Sulpetro stated that it had made arrangements whereby its gas under contract to both TransCanada and Pan-Alberta might be made available to Sulpetro, if required. If such were to occur and if the gas to be removed from the Province under the Sulpetro permit was to come from pools, fields, and areas not named in the permit, an application to amend the permit would be required.

7 FINDINGS AND DECISION

In light of its findings and responsibilities under the Act, the Board, with the approval of the Lieutenant Governor in Council, is prepared to grant Sulpetro Limited a new gas removal permit. The proposed permit would be in the form shown in the Appendix and would be subject to the terms and conditions therein contained as well as any conditions imposed by the Lieutenant Governor in Council.

DATED at Calgary, Alberta, on 15 February 1982.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

V E Bohme

V. E. Bohme, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

APPENDIX FORM OF PERMIT

IN THE MATTER of the Gas Resources Preservation Act, being chapter G-3 of the Revised Statutes of Alberta, 1980; and

IN THE MATTER of a permit to Sulpetro Limited authorizing the removal of gas from the Province

PERMIT NO. SL 82-2

WHEREAS Sulpetro Limited has applied to the Energy Resources Conservation Board for a permit pursuant to the Gas Resources Preservation Act authorizing the removal from the Province of gas produced from certain pools, fields and areas; and

WHEREAS the Board, upon inquiry into the application, has found that the Sulpetro Limited is a person who appears to have made arrangements to purchase gas within the Province and proposes to remove such gas from the Province, and that the provisions of the Gas Resources Preservation Act affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of the application for the removal of gas from the Province is in the public interest having regard to the present and future needs

of persons within the Province, and to the established reserves and the trends in growth and discovery of reserves of gas in the Province; and

WHEREAS the Lieutenant Governor in Council has given his approval by Order in Council numbered O.C. and dated , 198 .

THEREFORE, the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act, being chapter G-3 of the Revised Statutes of Alberta, 1980, hereby grants a permit to Sulpetro Limited (hereinafter called "the Permittee") authorizing the removal of gas from the Province, subject to the regulations and orders made pursuant to the said Act and to the terms and conditions prescribed in this permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be operative for a term commencing on 1 November 1983 and ending on 31 October 1991.

2. The quantities of gas that may be removed from the Province pursuant to this permit shall not exceed:

(a) a total of 4 653 000 000 cubic metres; and

(b) during any consecutive 12-month period ending October 31, rates limited by field productivity and good engineering practice, but in a 12-month period such rates shall not exceed:

(i) During the period November 1, 1983 to October 31, 1987, 775 500 000 cubic metres,

(ii) During the period November 1, 1987 to October 31, 1988, 620 400 000 cubic metres,

(iii) During the period November 1, 1988 to October 31, 1989, 465 300 000 cubic metres,

(iv) During the period November 1, 1989 to October 31, 1990, 310 200 000 cubic metres, and

(v) During the period November 1, 1990 to October 31, 1991, 155 100 000 cubic metres; and

(c) during any consecutive 24-hour period, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 2 125 000 cubic metres.

3. The quantity of gas that may be removed from the Province in accordance with clause 2, subclause (b), during any 12-month period ending October 31, may be augmented by any part of the quantity by which gas removed from the Province under the permit in the last preceding four-year period ending October 31, shall

have been less than the sum of the annual volumes stipulated in clause 2, subclause (b), of the permit to be so removed in the four-year period and which has not, in the meantime, been removed from the Province as an augmentation authorized by this clause, but nothing herein authorizes the removal of gas from the Province in any consecutive 24-hour period or during the term of the permit in excess of the volumes stipulated for such periods in clause 2.

4. Notwithstanding clause 2, subclause (c), the Permittee, for purposes only of alleviating temporary operating problems caused by pipeline or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized for such period by clause 2, subclause (c).

5. (1) The Permittee, subject to clause 6, may remove or cause to be removed from the Province under the authority of this permit, only gas produced from the following pools, fields and areas:

Antelope Field	Leahurst Field
Badger Field	Leo Field
Bilbo Field	Little Bow Field
Clair Field	Mudspring Field
Delia Field	Richdale Field
Desmarais Field	Rowley Field

Enchant Field	Sinclair Field
Fort Saskatchewan Field	Spirit River Field
Hackett Field	Stanmore Field
Ipiatik Field	Thorsby Field
Joarcam Field	Valhalla Field
Karr Field	Wembley Field

(2) Each pool, field or area named in clause 5, subclause (1) of this permit shall be construed as being the pool, field or area of the same name, as such pool, field or area may be designated from time to time by the Board, pursuant to the Oil and Gas Conservation Act.

(3) Where any pool, field or area named in this permit is revised or designated by the Board in a manner otherwise than by the name referred to herein, the Board may by stipulation hereto, substitute the revised name designated for any such pool, field or area named in this permit.

6. (1) For purposes of this permit, gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 5, subclause (1) may, subject to the provisions of subclauses (2), (3) and (4), be removed from the Province in substitution for gas produced or to be produced from pools, fields and areas named in clause 5, subclause (1).

(2) The total volume of gas removed from the Province during each 12-month period ending October 31, shall not exceed the total volume of gas actually produced from the pools, fields and areas named in clause 5.

(3) Gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 5, shall be deemed to be first used to supply sales to consumers, communities and utilities in Alberta, pipeline fuel and losses, and fuel and shrinkage at reprocessing plants in Alberta.

(4) For the purposes of this clause, all volumes shall be balanced on an energy basis.

7. The Permittee shall remove or cause to be removed pursuant to this permit only such gas as is delivered to it through facilities of NOVA, AN ALBERTA CORPORATION at the interconnection of the pipeline of NOVA, AN ALBERTA CORPORATION with the pipeline of TransCanada PipeLines Limited in the North-east quarter of Section 11 or the South-west quarter of Section 12, both in Township 20, Range 1, West of the 4th Meridian, near Empress, Alberta.

8. (1) All gas removed from the Province pursuant to this permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located at the points at

which gas is delivered in accordance with the approved points of removal referred to in clause 7.

(2) The relative density and higher heating value of all gas received by the Permittee through the facilities referred to in clause 7 shall be measured by or on behalf of the Permittee at the points at which gas is delivered by the said facilities.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

9. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this permit.

10. All quantities of gas for the purpose of this permit shall be referred to a 101.325 kilopascals pressure base and a 15 degree Celsius temperature base.

11. The Permittee shall supply gas from the pipeline of NOVA, AN ALBERTA CORPORATION at a reasonable price to any community or

consumer, within the Province, or to any public utility requiring gas for such community or consumer that is willing to take delivery of gas at a point on the pipeline transmitting the gas, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

12. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 11 and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

13. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
Vice Chairman

R226 N

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

AMOCO CANADA PETROLEUM COMPANY LIMITED
AND PEMBINA PIPE LINE COMPANY LTD.
PERMITS TO CONSTRUCT PIPELINES
IN THE WEST PEMBINA AREA

Decision 82-9
Applications 810514
and 810999

1 THE APPLICATIONS

Amoco Canada Petroleum Company Ltd. applied (Application 810514) to the Energy Resources Conservation Board (Board) for a permit to construct 24.86 kilometres (km) of 88.9 millimetre (mm) outside diameter pipeline to transport ethane, propane, butanes, pentanes, and pentanes plus from proposed gas plants to be located in Lsd 15-10-47-14 W5 and Lsd 9-34-47-13 W5 to an existing pipeline located in Lsd 4-31-48-12 W5.

Pembina Pipe Line Ltd. applied to the Board (Application 810999) for a permit to construct 64.07 km of 168.3 mm, 114.3 mm and 88.9 mm outside diameter pipeline from an existing Chevron Canada Ltd. (Chevron) plant located in Lsd 11-22-49-12 W5 and a proposed Hudson's Bay Oil and Gas Company Limited (HBOG) gas plant to be located in NW 1/4 10-47-14 W5, to the existing Pembina system; to make certain changes to, and dedicate certain portions of the existing system for the purpose of transportation of segregated condensate (see Figure 1).

Hudson's Bay Oil and Gas Company Limited had also applied to build a pipeline in the general area but withdrew its application prior to the hearing.

2 THE HEARING AND DECISION

A public hearing of the applications was held in Drayton Valley on 26 January 1982, with G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and E. J. Morin, P.Eng., sitting.

At the conclusion of the hearing, the Board stated that since both of the applications were in the public interest, it was prepared to approve them, subject to the approval of the Minister of the Environment with respect to matters relating to the environment. This brief report is intended to give in writing the Board's reasons for its decision.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives Abbreviations used in Report)	Witnesses
Amoco Canada Petroleum Company Ltd. (Amoco) B. Major, Q.C.	R. Nicholls, P.Eng. F. Matthews, P.Eng. B. Rose, P.Eng. D. Mascandelli R. Finley F. MacCallum Dr. D. Cowan
Pembina Pipe Line Ltd. (Pembina) A. Hollingworth	A. G. Horne L. E. Gano P. Dau, P.Eng.
Petro-Canada Exploration Inc. (Petro-Canada) W. Gallagher	
Energy Resources Conservation Board staff D. Holgate A. Cassley, P.Eng. I. Cameron	

3 THE PROPOSALS

3.1 Amoco's Proposal

Amoco stated that the applied for pipeline was a short extension to its existing natural gas liquids (NGLs) collection system. The extension was designed to handle NGLs from two proposed gas plants, and, even though one proposal had not materialized, the volumes to be shipped from the one plant adequately justified the economic investment. Any future incremental volumes would serve to reduce the overall tariffs.

Amoco stated that in selecting the route for the pipeline it had made use of existing rights of way and cut lines where possible, but had diverged from these to cross the Pembina River and Dismal Creek at points which would avoid high erosion and siltation problems. The route selected does not cross any agricultural or settled areas and the company said that its mitigative measures would ensure only very minimal environmental impact in the area.

Amoco also stated that, as producers develop enhanced oil recovery projects in the area which requires NGLs for injection, it will make available volumes of NGL as required, and will backflow the system if necessary to supplement local sources. The NGLs would probably be made available at the Buck Creek fractionation plant or in Edmonton.

3.2 Pembina's Proposal

In view of projected increases in the volumes of condensate to be shipped from the area, Pembina stated that it proposed to dedicate certain existing crude oil lines to condensate service, and to construct pipelines from the existing Chevron gas plant and the proposed HBOG gas plant to connect into this condensate system. A number of minor modifications to the existing system had already been made to ensure continued service to crude oil producers in the area. The company stated that by utilizing an existing tank at the Buck Creek Pump Station the condensate would be batched to Edmonton through the existing 406.4 mm line.

Pembina said that in selecting routes for the proposed pipelines it had parallelled the Amoco right of way for a portion of the route from the HBOG plant. The more direct route was believed to be in the path of a possible extension of the Brazeau reservoir. For the connection to the Chevron plant the company stated that it had considered a more indirect route using existing Amoco rights of way but had rejected this because of the greater length involved with no significant compensating environmental benefit. Existing cut lines had been used where possible with minor deviations to allow for the best choice of river crossings and to avoid an oil well site. Pembina stated that both pipeline routes traversed unoccupied land with soils having very low capability for agricultural use.

4 Views of PetroCanada

PetroCanada stated that it now supports both applications whereas its original intervention was in opposition to the applications.

5 CONCLUSION

The Board is satisfied, on the basis of the evidence placed before it at the hearing, that there is a need for both of the proposed pipelines. It is also satisfied that the technical design of the proposed facilities meets the requirements of the Pipeline Act. The Board recognizes that the proposed routes for the pipeline are not necessarily the most direct, and thus of the shortest distance, but it is satisfied that the proponents investigated other routes and had valid reasons for selecting the proposed routes. The Board is satisfied that the related environmental impact will be at an acceptable level.

The Board also finds acceptable the degree to which the proposals will serve conservation. In particular, it notes Amoco's undertaking to backflow natural gas liquids into the area should this become necessary for enhanced recovery purposes, and that the Pembina application provides for the segregation of condensates for shipment to Edmonton. The Board also notes no parties present at the hearing objected to either of the applications. Accordingly, the Board confirms its decision announced at the conclusion of the hearing and subject to receipt of the necessary approvals from the Minister of Environment, is prepared to issue permits for the applied for facilities.

ISSUED at Calgary, Alberta on 19 February 1982.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
G. J. DeSorcy
Vice Chairman

C. J. Goodman
C. J. Goodman
Board Member

E. J. Morin
E. J. Morin
Acting Board Member

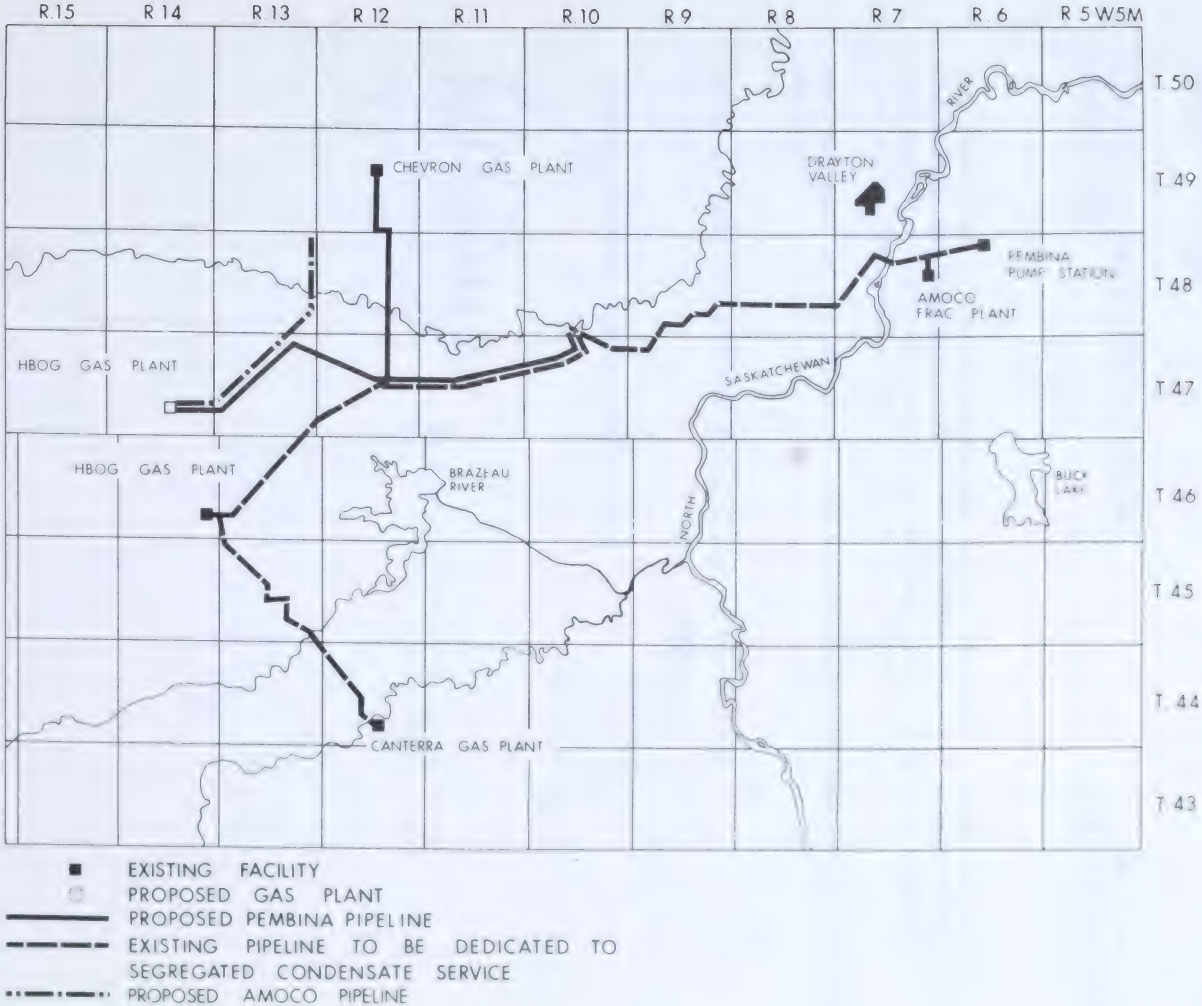
R.15
R 14
R.13
R 12
R.11
R.10
R 9
R 8
R 7
R. 6
R 5 W5M
T. 50
T. 49
T 48
T 47
T 46
T 45
T. 44
T. 43
CHEVRON GAS PLANT
DRAYTON VALLEY
RIVER
PEMBINA PUMP STATION
AMOCO FRAC PLANT
SASKATCHEWAN
NORTH
HBOG GAS PLANT
HBOG GAS PLANT
BRAZEAU RIVER
CANTERRA GAS PLANT
EXISTING FACILITY
PROPOSED GAS PLANT
PROPOSED PEMBINA PIPELINE
EXISTING PIPELINE TO BE DEDICATED TO SEGREGATED CONDENSATE SERVICE
PROPOSED AMOCO PIPELINE

FIGURE 1

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION FOR COMPULSORY POOLING
ELNORA FIELD

Decision 82-10
Application 810882

The Board has reviewed the report of its examiners, attached hereto respecting Application 810690 for an order that all tracts within the drilling spacing unit comprising section 36-34 23 W4M be operated as a unit for the production of gas in the Elnora Field.

For purposes of its decision, the Board adopts the examiners' recommendations.

DATED at Calgary, Alberta this 5th day of March 1982.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy

G. J. DeSorcy
Vice Chairman

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY ASHLU EXPLORATION LTD.
COMPULSORY POOLING — Examiners' Report E82-2
ELNORA FIELD — Application No. 810882

1 INTRODUCTION

1.1 The Application

Ashlu Exploration Ltd. (Ashlu) applied pursuant to section 72 of the Oil and Gas Conservation Act to have all tracts within section 36, township 34, range 23, west of the 4th meridian operated as a unit for the production of gas from the Belly River Formation, the Glauconitic Sandstone, and the Basal Quartz Sandstone. Ashlu proposed that the production from the well ASHLU ET AL ELNORA 8-36-34-23 be allocated to each tract on an areal basis. Ashlu owns the mineral rights to the south half of section 36. In the north half of section 36, the Glauconitic rights are owned by the Elnora Gas Unit (the Unit), and the balance by the Kerr-McGee Corporation (Kerr-McGee).

As operator of the Unit, Kerr-McGee filed an intervention to the application.

1.2 The Hearing

A public hearing of the application commenced on 22 December 1981 in Calgary, Alberta, before Energy Resources Conservation Board-appointed examiners R. W. Edgecombe, P.Eng., D. G. Pearson, P.Eng., and M. J. Vrskovy, P.Geol. Kerr-McGee requested a 30-day adjournment of the hearing on the grounds that insufficient notice had been given by the Board and thus the Board had no jurisdiction to rule on the application. Kerr-McGee said that it had had insufficient time to contact the working-interest owners concerning the application, and that notice had not been sent to all the relevant parties. The examiners were of the opinion that sufficient notice had been given and denied the request for adjournment.

Kerr-McGee then filed an application pursuant to section 34 of the Energy Resources Conservation Act to have the hearing conducted by Board members. A Board panel consisting of N. Berkowitz, P.Eng., C. J. Goodman, P.Eng., and V. E. Bohme, P.Eng., then considered the request for adjournment and the application for a Board hearing. The Board denied the request for a Board hearing but granted an adjournment to 19 January 1982.

The hearing reconvened on 19 January 1982, at which time Kerr-McGee stated it had no authority to represent the Unit and was appearing solely on its own behalf. As a result Natomas Exploration of Canada

Ltd., which has a 30 per cent working interest in the Unit, was granted intervener status.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Ashlu Exploration Ltd. (Ashlu) H. R. Ward	H. D. Borgland H. R. Hegland
Kerr-McGee Corporation (Kerr-McGee) B. K. O'Ferrall	M. Milne
Natomas Exploration of Canada Ltd. (Natomas) G. R. Heming, P. Eng.	G. R. Heming, P.Eng. R. D. White, C.E.T.
Energy Resources Conservation Board staff (Board staff) W. Elsner, P.Geol. D. Holgate N. F. Lord J. Page L. A. Schmidt	

2 THE ISSUES

The examiners believe the issues to be:

- o the need for a pooling order; and
- o the manner in which costs are to be recovered.

3 THE NEED FOR A POOLING ORDER

3.1 Views of Ashlu

Ashlu submitted that repeated attempts to reach a voluntary agreement with Kerr-McGee on the pooling of tracts in section 36 on an areal basis had been unsuccessful. These attempts had been made during the period from 20 January 1981 to 15 January 1982. In May 1981, Ashlu drilled a well that penetrated the Belly River, Glauconitic, and Basal Quartz. Ashlu submitted that the Glauconitic was the zone of primary interest, but said the Belly River and the Basal Quartz, which appeared to have hydrocarbon potential, but were as yet untested, were included in the application for the sake of expediency, in case they also should prove to be commercially productive.

3.2 Views of the Interveners

Kerr-McGee submitted that it was not opposed to pooling the tracts nor was it opposed to pooling on an areal basis.

Natomas submitted that it was not opposed to pooling on an areal basis but it opposed the inclusion of all three zones in one pooling order. Natomas contended that any pooling order issued should include only the Glauconitic because it was the only zone where the hydrocarbon productivity had been tested.

3.3 Views of the Examiners

The examiners believe that a reasonable attempt to reach a pooling agreement has been made, and because no opposition to the basic proposal was made at the hearing, the issuance of a pooling order based on area would be appropriate. The examiners further believe that, due to the absence of evidence of commercial production from the Belly River and the Basal Quartz, the pooling order should apply only to the Glauconitic which, tests reveal, has hydrocarbons in commercial quantities. The examiners note that if the Belly River, Basal Quartz, or both prove to be economically productive at a later date and voluntary pooling is not possible, the affected party could make application for other compulsory pooling orders.

4 THE RECOVERY OF COSTS

4.1 Views of Ashlu

Ashlu requested that it be allowed to recover the drilling costs attributed to the other mineral rights owners within 30 days of the date of the pooling order. It further requested that if such payment were not paid within the time specified in the order, it should be allowed to recover 150 per cent of the amount. Ashlu submitted that its request for a 50 per cent penalty was made because that was the maximum amount allowed under section 72(5) of the Oil and Gas Conservation Act. Ashlu stated that it did not consider this request unreasonable as it is common practice in industry to have penalties of 200 per cent or higher in the case of a development well where one party does not wish to participate in the drilling risk. Ashlu also stated that if a penalty were not awarded, it believed that the interest on funds it had spent on behalf of the other mineral owners should be substantially greater than the prime interest rate plus 1 per cent in order that it could recover an acceptable rate of return on its investment.

Ashlu submitted that the costs of drilling the well should be recovered from Glauconitic production, but agreed that the costs of drilling beyond the Glauconitic should be excluded.

4.2 Views of the Interveners

Kerr-McGee submitted that it was not opposed to a non-participation penalty of 50 percent.

Natomas submitted that it was opposed to a penalty of 50 per cent unless this was justified. Natomas, however, stated it was aware that normal practice in industry was to set penalties in the order of 200 per cent for development wells and 300 to 500 per cent for exploration wells.

Natomas also stated that the costs of drilling the well should not exclusively be recovered from Glauconitic production but should be at least partially allocated to other formations. Natomas acknowledged however that depending on the life of the Glauconitic reserves the well bore may not be suitable for recompletion in other formations when the Glauconitic is depleted.

4.3 Views of the Examiners

Section 72(5) of the Oil and Gas Conservation Act states that "The Board in its order may specify that, in the event production of oil or gas is obtained and the owner of a tract fails to pay his share of the actual cost of drilling the well by the time specified in the order, then the amount payable by that owner shall include, in addition to his tract's share of the actual cost of drilling, a penalty payable to the operator but not exceeding one half of his tract's share of the actual cost of drilling."

The examiners believe that in the case where an operator has demonstrated that he has made reasonable attempts but has been unsuccessful in reaching an agreement, and is willing to take the risks in drilling a well and proving up reserves, the application of a penalty as permitted by the Oil and Gas Conservation Act is warranted.

The examiners also believe that a non-participant should be allowed up to 30 days to pay its share of the costs, following receipt of a statement in writing of the tract's share, without incurring a penalty.

The examiners further believe that interest should be applied to all monies, including the penalty, not paid within the time specified. Since a non-participating party has the right to pay its share of costs within the time set out in the pooling order, and incur neither a penalty nor interest charges, the examiners believe that if the non-participant fails to pay its share of costs it should be charged interest on the outstanding amount until its share of the costs and the penalty have been paid.

In this case the examiners are satisfied that Ashlu has made reasonable attempts to reach an agreement and was unsuccessful. Consequently, they believe that if the non-participant fails to pay its share within 30 days of the receipt of the statement of costs, a 50 per cent penalty should be assessed and the non-participant charged interest on the outstanding monies until the account has been paid in full.

The examiners believe that only those costs attributable to drilling and completing a well for production from the Glauconitic should be used when determining the non-participants' share of the costs.

With regard to how the drilling costs are to be distributed to each prospective productive formation the examiners believe that this is a matter to be resolved by the working interest owners of section 36. In the event of a dispute the matter can be referred to the Board.

5 RECOMMENDATION

The examiners recommend that:

(1) the Board, with the approval of the Lieutenant Governor in Council, issue an order under section 72 of the Oil and Gas Conservation Act that the two tracts in section 36-34-23 W4M, namely the northern and the southern halves of the section, be operated as a unit for the production of gas from the Glauconitic Sandstone;

(2) the order specify that the allocation to each tract of its share of the drilling and completion costs and production of gas from the drilling spacing unit shall be on an areal basis.

(3) the order specify that, if the non-participating party's share of the drilling costs is not paid within 30 days of receipt of the statement of costs, a penalty equal to 50 per cent of that amount be awarded to the applicant.

(4) the order specify that, if the non-participating party's share of the drilling costs is not paid within 30 days of receipt of the statement of costs, the maximum interest rate that Ashlu may charge on the unpaid balance of monies owed, including the penalty, be set at the prime interest rate plus one per cent.

DATED AT Calgary, Alberta, on 25 February 1982.

R.W. Edgecombe

R. W. Edgecombe, P.Eng.

D. G. Pearson, P. Eng.

M. Vrskovy, P.Geol.

Alberta
ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

ESSO RESOURCES CANADA LIMITED
PROPOSED DEEP-CUT FACILITIES
JUDY CREEK AREA GAS PROCESSING PLANTS

Decision 82-11
Application 810417

1 INTRODUCTION

1.1 The Application

Esso Resources Canada Limited applied, pursuant to section 38 of The Oil and Gas Conservation Act[1], for approval to extract a mixture of ethane and heavier hydrocarbons (ethane plus) from the natural gas processed at the Judy Creek Gas Conservation Plants (hereinafter referred to as "the existing plant") located in legal subdivision 15 of section 25, township 64, range 11, west of the 5th meridian. The plant is currently designed to process a maximum of 7.466×10^6 cubic metres per day (m^3/d) of raw sour gas from which a maximum of 5.128×10^6 m^3/d of sales gas and 5768 m^3/d of propane plus is recovered. The proposed modifications would result in the recovery of 2955 m^3/d of ethane plus. The emission of sulphur dioxide to the atmosphere would not exceed the presently-approved maximum of 1.0 tonne per day.

1.2 The Interventions

The application was supported by six, and opposed by eight, interveners. Those in support of the application based that support mainly on their view of proprietary rights of producers to handle gas products as the producers see fit, provided such handling satisfies the requirements of economic, orderly and efficient development of oil and gas resources. Those in opposition to the application based that opposition mainly on the view that approximately the same amount of ethane could be recovered at existing straddle plants at a lower cost. In their view, the application proposed an unnecessary duplication of facilities which would raise the provincial cost-of-service of producing ethane, and thus ethylene, for the Alberta petrochemical industry.

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1 Now section 26 of the Oil and Gas Conservation Act.

1.3 The Hearing

The application was considered at a public hearing in Calgary with N. Berkowitz, P.Eng., G. J. DeSorcy, P.Eng., and F. J. Mink, P.Eng. sitting. The hearing convened on 9 November 1981, continued on 10 and 17 November 1981, and concluded on 7 December 1981.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Esso Resources Canada Limited (Esso) J. B. Ballem, Q.C.	J. W. Park, P.Eng. B. D. Smith, P.Eng. Dr. P. D. Grout, P.Eng.
Alberta and Southern Gas Co. Ltd. (A&S) F. G. Homer	
Alberta Natural Gas Company Ltd. (ANG) R. M. Cairns	
Amoco Canada Petroleum Company Ltd. (Amoco) V. J. Carson	
Canadian Hunter Exploration Ltd. (Cdn. Hunter) B. K. O'Ferrall	D. L. Bowman, P.Eng.,
Chevron Standard Limited (Chevron) R. A. Pashelka	
Gulf Canada Resources Inc. (Gulf) J. D. Anderson	W.A.J. Hellofs R.A.L. Clarke, P.Eng. H. B. Holmberg, P.Eng.
Northwestern Utilities Limited (NUL) J. W. Beames, Q.C. C. K. Sheard	D. L. Weiss, P.Eng.
Shell Canada Chemical Company (Shell) R. M. Curtis	J. E. Colbert, P.Eng.

cont'd THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Texaco Canada Resources Ltd. (Texaco) J. Zych	
Union Carbide Canada Limited (Union Carbide) G. N. McDermid	
Alberta Energy Company Ltd. Esso Chemical Company Hudbay Chemical Company (AEC/ECC/HCC) D. G. Hart, Q.C.	
Alberta Ethane/Ethylene Petrochemical Project (AEEPP) F. Foran	Dr. J. E. Feick of NOVA, AN ALBERTA CORPORATION R. E. Bowser, P.Eng. of Alberta Gas Ethylene Company Ltd. W. W. McCagherty of Dow Chemical Canada Inc.
C-I-L Inc. Trimac Limited (CIL/Trimac) E. O. McAvity	
Dome Petroleum Limited CU Ethane Limited (Dome/CUE) F. M. Saville	Dr. A. H. Younger, P.Eng. J. Caffrey, P.Eng. E. Kuczma, P.Eng. R. Roberts, P.Eng. all of Dome Petroleum Limited A. Scott, P.Eng. of CU Ethane Limited
Energy Resources Conservation Board staff M. J. Bruni J. D. Dilay, P.Eng. D. I. Mulrain W. J. Schnitzler, P.Eng.	

1.4 Background

The existing Judy Creek processing plant produces a residue gas for sale to NUL, A&S, and Amoco, and a propane plus liquid product which is routed to the Fort Saskatchewan area for fractionation.

On 19 October 1981, the Gas Utilities Board (GUB) heard an application by Esso to remove all restrictions upon Esso with respect to the recovery and marketing of ethane from gas owned and acquired in the Judy Creek area, with particular reference to ethane reserved for use by C-I-L Inc. (CIL).

In the resulting Decision No. 81-1, GUB[2] acknowledged that "the circumstances respecting ethane supply to the petrochemical industry have changed since 1962" when the restrictions were first set in place, but that it "does not believe that these changing circumstances have negated the original intent of protecting a supply of ethane to CIL". GUB concluded that "protecting ethane supplies to CIL should be for a definite period of time" and that "the protection should not be unrestricted in terms of volume". Therefore GUB limited the protection to mid-1988, consistent with the commitment of gas to NUL, while the volume of ethane was limited to the "requirements of CIL for its low-density polyethylene facility, including the expansion currently underway."

Notwithstanding the above-mentioned restriction respecting a portion of the ethane from the area served by the existing plant, most of the Judy Creek gas and the ethane contained therein is available for disposal as the owners deem appropriate and as approved by the Board. The bulk of that volume of gas is currently being reinjected into the Swan Hills South miscible flood operated by Amoco, with certain amounts being used in the area as fuel and the remainder being routed through the Dome/CUE plant in Edmonton for liquids removal prior to use of the gas in the Edmonton area. The resulting specification ethane product from the Edmonton plant is routed via pipeline to the Alberta Gas Ethylene Company Ltd. (AGE) ethylene plant at Joffre for upgrading or to the Cochin pipeline for removal from the province.

The currently-operating ethylene plant (AGE I) is the first of three ethylene plants intended to be operating at the Joffre site by 1985/86. AGE II was approved by an Industrial Development Permit issued earlier in 1981 and is under construction. The Board heard an application for AGE III in April 1981, and the Board's decision was released in mid-1981 indicating the Board was prepared to issue a permit for the project upon receipt of an authorizing Order in Council. No order has been received to date. The annual potential demand for 94 per cent ethane feedstock by these three plants is some 7.9×10^6 m^3.

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2 In the Matter of an Application by Esso Resources Canada Limited for amendment to Gas Utilities Board Approval No. 72-1, as amended. Gas Utilities Board Report: Decision No. 81-1, 3 November 1981.

The current and intended sources of supply of ethane for the AGE plants are the pipeline reprocessing (straddle) plants at Cochrane, Empress, and Edmonton (the Dome/CUE plant), and the Waterton field deep-cut plant, along with proposed facilities at the Jumping Pound plant. Expansions or new facilities are also planned at Cochrane and Empress.

The issue of extraction of ethane and LPGs at straddle plants vis-a-vis field plants has been addressed to the Board on several occasions, one of the more recent examples being at a 1976 hearing to consider the expansion of the Edmonton liquids plant for ethane recovery. At that time, the Board heard both sides of the argument and in Decision 76-2 recognized the possibility that a producer might wish at some time to "upstream" an existing straddle plant. The Board concluded, in that decision that "there may be certain economic and conservation advantages in recovering ethane at straddle plants rather than field plants". The Board went on to state that this would not necessarily be the situation in all instances and that, in the event of an application to install ethane recovery facilities in a field plant upstream of the straddle plant, such an application would be considered by the Board in the light of circumstances prevailing at the time. The Board concluded that "an approval of the applied-for facilities would not preclude the subsequent approval by the Board and the installation of ethane recovery facilities in field locations upstream of the plant" and that "such possibility is, in the Board's view, a business risk which the applicant would have to contend with".

2 ISSUES

The broad matter to which the Board has addressed itself is whether the facilities proposed by Esso for the processing of gas to recover ethane would provide for the economic, orderly, and efficient development of oil and gas resources in the public interest of Alberta. In addressing this matter the Board considers there are several issues which are important. However it believes that a fundamental matter on which an assessment of public interest must be based is the degree, if any, to which the proposed facilities would recover ethane incremental to that which would be recovered should the proposed facilities not be constructed. It is the Board's view that an analysis of this question is a prerequisite to an assessment of the issues which constitute the public interest. These further issues include the following major matters:

- the cost of ethane to be recovered at the proposed facilities compared with the cost of recovering the ethane (or similar volumes) at other locations in the province,

- the impact on the petrochemical industry in Alberta.

The following aspects of public interest, while not "major" issues in this particular instance, are also important considerations:

- the degree of upgrading of resources in the province,

- the conservation and environmental impact aspects of the proposed facilities, and

- other public interest matters such as impact on the Alberta Treasury, propietary rights of producers, prospects for increasing production of shut-in gas, impact on potential enhanced oil recovery operations in the Judy Creek area, and the impact on gas consumers in the Edmonton area.

The Board believes that an evaluation of the above list of public interest issues would depend on its conclusions respecting the first issue; that is, whether all or part of the ethane that would be recovered in the proposed facilities would be incremental recovery. It thus addresses this question first. In reviewing the remaining issues, the Board is in effect comparing the public interest impacts of approving the proposed Judy Creek facilities to the public interest impacts that would result from a denial of the application and a continuation of the situation which currently prevails or could be expected in such a circumstance.

3 INCREMENTAL ETHANE

3.1 Views of the Applicant

Esso stated that 80 per cent of the ethane extracted at the proposed facilities would be net incremental ethane. The figures for the years 1984 to 2000 indicated that the amount of incremental ethane would range from as high as 95 per cent in 1985 to as low as 63 per cent in 1995.

These figures were based on the assumption that in the absence of Esso's proposed project the current disposition of Judy Creek gas would continue; that is, gas rich in ethane (currently containing 20+ per cent ranging down as low as 13 per cent by the year 2000) would continue to be used for the Swan Hills South miscible-flood scheme and as fuel in the area, with any balance of gas being available to NUL for transmission to the Edmonton area. Esso stated that gas in excess of miscible flood and fuel requirements would range from virtually zero in the late 1980s to somewhat higher than the capacity of the NUL transmission system in subsequent years.

3.2 Views of the Interveners

The interveners supporting the application did not present evidence on this matter. However, they supported in principle the concept that Esso's scheme would result in significant additional ethane production compared to the existing situation.

The interveners opposing the application, particularly AEEPP and Dome/CUE, stated that the Judy Creek ethane should be made available to the petrochemical industry through the AEEPP facilities already in existence, particularly through the currently under-utilized Edmonton liquids plant. They argued that the ethane-rich Judy Creek gas should go to Edmonton where it would be processed at the Edmonton plant. The miscible flood and fuel requirements in the Judy Creek area should then come from a lower ethane content gas stream which could be moved into the area. They stated that if such were the disposition of the Judy Creek gas, Esso could not demonstrate that its proposal would recover any incremental ethane over that otherwise recoverable. Dome/CUE calculated that the incremental volume of ethane which would be recovered by diverting the Judy Creek gas to Edmonton would be approximately 8 per cent greater than the incremental volume of ethane which it calculated would be recovered by Esso's proposal.

3.3 Views of the Board

In preparing an assessment of the incremental ethane recovery which would result from the applied-for facilities, the Board recognizes that the most significant factors are the assumptions which are made in establishing the baseline ethane recovery to which recovery resulting from the application is compared.

The Board agrees with Esso that if the current disposition of Judy Creek gas is used as the basis for comparison, the proposed scheme shows a substantial incremental gain in ethane extraction at the Judy Creek facility as compared to that which would be recovered at the Edmonton straddle plant. This occurs because the current disposition of Judy Creek gas involves the use of most of it for enhanced recovery in the area with little of it being transmitted to the Edmonton area. Thus, most of the ethane which would be recovered in the proposed Judy Creek facility would be incremental production during the time period when substantial gas is expected to be used for enhanced recovery in the Judy Creek area. Thereafter, much of the gas would be transported to the Edmonton area in any case, and thus the incremental ethane recovered at Judy Creek would decline. It should be noted that the ethane which would be recovered at Edmonton in this situation would include volumes reproduced from gas injected into reservoirs in the early years of the forecast period.

The Board believes the incremental ethane recovery calculated in this manner can be termed the "maximum incremental ethane recovery case". It calculates that, for this case, over the period 1984 to 2000 the portion

of the ethane recovered in the proposed facilities that would be incremental to that otherwise recoverable would be some 6.8 x 10^6 m^3 or 75 per cent. This estimate is some 5 per cent lower than Esso's estimate because the Board accepts the evidence presented by Dome/CUE regarding a 96 per cent recovery factor for its Edmonton plant, rather than 91 per cent as assumed by Esso. The Board's year-by-year analysis indicates that the incremental recovery during the initial portion of the period (1984 to 1988) would be over 90 per cent, declining to approximately 50 per cent in 1994, and thereafter rising to near 70 per cent by the year 2000, the terminal year of the study period.

The Board considers that the maximum incremental ethane recovery calculated in the above-described manner reflects a considerable degree of uncertainty because it is based on the premise that the current disposition of ethane-rich Judy Creek gas would continue uninterrupted if Esso's application were to be denied. The Board believes that if the proposed Esso facilities were not installed, the disposition of the Judy Creek gas could differ considerably from what is currently taking place and accordingly considers it appropriate to estimate the incremental ethane recovery for at least one other alternative disposition of the residue gas.

The alternative scenario selected by the Board is one which assumes that in the absence of ethane extraction facilities in the Judy Creek area, changes would be made to bring other gas streams containing less ethane into the area for injection as push gas, allowing the ethane-rich Judy Creek gas to move to Edmonton. This would result in what the Board terms the "minimum incremental ethane recovery case". The possibility of this case occurring would largely depend on business arrangements between producers, shippers and processors and could require upgrading of transportation or processing facilities. There is clearly uncertainty as to whether these changes could be brought about.

The Board calculates for this minimum incremental case that, over the study period 1984 to 2000, some 3.9 x 10^6 m^3 or 40 per cent of the ethane to be extracted at the proposed facilities would be incremental ethane. The major reason that this estimate does not agree with that in the Dome/CUE submission, which was based on a similar scenario, is that the Board estimate assumes that during the first few years of the study period, when on a comparative basis considerably increased volumes of Judy Creek gas would enter the Edmonton straddle plant, equivalent volumes of other gas, calculated on a heating value basis, would not be able to continue entering the Edmonton market. Therefore the ethane associated with that backed-out volume of other gas would negate a portion of the gain in ethane recovery achieved by handling the Judy Creek gas. The Board's year-by-year analysis of this minimum incremental case indicates that the incremental recovery during the initial portion

of the period (1984 to 1992) would be in the range of 30 to 45 per cent and that the incremental recovery figure would rise thereafter to approximately the range previously indicated for the maximum incremental case.

Appendix I to this report indicates the major assumptions which were used as the basis for calculating the maximum and the minimum incremental ethane recovery cases.

The Board recognizes that the volumes of ethane that would be available from Judy Creek after the year 2000 would be different in the maximum and minimum case. It does not expect that this difference would be significant enough to affect the decision, particularly bearing in mind the discount factor that would be applicable to any economic impact and the uncertainties related to a period so far in future.

In view of the significant difference between the maximum and minimum incremental ethane cases, and bearing in mind the considerable uncertainty in the assumptions forming the baseline for each case, the Board considers it appropriate to carry forward both of them and to assess the public interest aspects of the application for each of the cases. Having assessed, for each case, the impacts on the Alberta public interest of an approval or a denial of the subject application, the Board will then make an overall decision which in turn reflects its views as to which case is the more appropriate basis for the decision.

4 COST OF ETHANE

4.1 Views of the Applicant

Esso stated that the capital cost of the proposed expansion would be between $48 and $65 million (1981 dollars). On a cost-of-service basis, ethane from the proposed facility would be more expensive than from existing ethane suppliers. Esso testified, however, that the price of ethane from its proposed facility would be competitive. It said that the appropriate comparison for a new source of ethane is with alternative sources. Although it expressed some concern that a delay in the project would increase its cost, Esso felt that the cost effectiveness of the proposed plant as a source of ethane was not significantly related to the timing of the Board's consideration of the application.

4.2 Views of the Interveners

Dome/CUE and AEEPP said that the Esso proposal was not the most cost effective way of extracting Judy Creek ethane and would unnecessarily

increase the cost of ethane to Alberta's petrochemical industry. AEEPP estimated that the Judy Creek facilities would increase the cost of ethane from the Edmonton straddle plant by $6.5 million per year by 1985.

Dome/CUE presented evidence with respect to ethane cost of service under various scenarios. A 1985 cost of service of $\$24.70/m^3$ ($3.90/bbl) for ethane at the Edmonton plant would result if the entire Judy Creek rich gas stream were processed there. If 1.6×10^6 m^3/d (58 MMcfd) of rich Judy Creek gas were processed at Edmonton in 1985 the cost of service would be $\$24.75/m^3$ ($3.91/bbl). If a like amount of lean Judy Creek gas were moved through Edmonton in 1985 the cost of service would be $\$40.90/m^3$ for ethane. The estimated ethane cost of service associated with the proposed 56×10^6 m^3/d (2 bcfd) straddle plant at Empress was given as $\$25.05/m^3$ ($3.96/bbl) in 1985. Dome/CUE said these costs compare with the $\$44.30/m^3$ ($7.00/bbl) for the ethane cost-of-service estimate provided by Esso.

4.3 Views of the Board

The Board is of the view that if the application were approved, the ethane recovered at Judy Creek would cost more than Judy Creek ethane recovered at the Edmonton straddle plant. However, since the Esso proposal involves the recovery of incremental volumes of ethane over and above what could be recovered at Edmonton, the Board believes that a comparison of costs at the Edmonton plant to those at the proposed facilities is improper. Rather, the Board believes the proper comparison is of the cost of the ethane proposed for recovery at Judy Creek against the total of the cost of that portion which could be recovered at Edmonton plus the cost of the increment recoverable at Judy Creek but not at Edmonton and which would have to be recovered from other sources in the province during that time if there was a demand for the ethane. The Board has made this comparison for the two incremental ethane recovery scenarios which have been identified earlier.

Maximum Incremental Case

In order to evaluate the cost of incremental ethane for this case, the savings in operating costs at the Edmonton plant due to lower ethane production were subtracted from the capital and operating costs of the proposed facilities at Judy Creek. It was determined that the incremental ethane recovery at Judy Creek for the maximum incremental case was of considerably lower cost than equivalent volumes from an alternative source in the province not now producing specification

ethane or planned for production in the near future. The incremental production from a Judy Creek facility, which in this case would amount to some 75 per cent of the total production, was so much less costly than from alternative sources in the province that it resulted in a total cost for the Judy Creek volumes which was less than the total cost for the same volume recovered to the extent practical at Edmonton with the other volumes coming from the next least-costly ethane source in the province.

The Board estimates that in this case the comparable total undiscounted cost of recovering the same volume of ethane in the 1984-2000 period would be some 4 times greater than the costs at Judy Creek or some $700 million higher than the applicant's cost.

The Board also analysed the impact which approval of the application would have on the cost of ethane from existing sources. The rolled in cost of ethane would increase by \$1.20 per m^3 (this represents an increase of some 2 per cent) in 1985 if the Esso facility were constructed. It is emphasized that such an increase has regard only for existing sources and is not considered very significant in terms of the competitive value of ethane as a petrochemical feedstock. Since the proposed Esso facilities would provide a substantial increment of production at a lower cost than would be possible elsewhere in the province, this impact on the rolled-in cost of ethane is overstated if long-term increases in production over existing levels are considered. The Board also believes that approval of the application would not materially affect the viability of the Dome/CUE operation in the long run. The Board expects that, given a demand for ethane, alternative streams of gas would be routed to that plant, thus taking advantage of its cost effectiveness which in turn would impact on the long-term rolled-in cost of ethane.

Minimum Incremental Case

In order to evaluate the cost of incremental ethane for this case, it was necessary to deduct from the capital and operating costs of the proposed facilities any other costs which would be incurred if the entire volume of Judy Creek gas were processed at the Dome/CUE plant. These costs include capital and operating costs for looping the NUL pipeline and operating costs which vary with ethane production at the Dome/CUE plant. The unit cost of incremental ethane from Judy Creek was calculated on this basis. The cost of ethane from other gas plant facilities was also calculated.

The Board's analysis indicates that the incremental ethane recovery for the minimum incremental case, would be at lower cost at the proposed Judy Creek facilities than from alternative sources. Once again, even though the increment would now be lower, it would be available at so

much lower a cost at Judy Creek than elsewhere in the province, that it would offset the cost advantage for the portion recoverable at Edmonton and result in a lower total cost for the total recoverable volume.

The Board estimates that in this case the comparable total undiscounted cost of recovering the same volume of ethane in the 1984-2000 period would be some 3 times greater than the costs at Judy Creek or some $500 million higher than the applicant's cost.

Approval of the application would have the same impact on the cost of ethane from existing sources as indicated in the maximum incremental case.

The Board notes that its analyses for the maximum and minimum incremental recovery cases refer to total costs of recovering the same volumes of ethane that could be recovered at Judy Creek. If, in fact, there were no demand for the ethane in question, the benefits favouring the Judy Creek proposal are overstated.

5 IMPACT ON THE PETROCHEMICAL INDUSTRY

5.1 Views of the Applicant

Esso stated that its proposal would provide an additional supplier of ethane, thereby increasing competition, improving the security of supply and increasing the supply of ethane to the Alberta petrochemical industry. Esso provided evidence to support its supposition that the impact on Dome/CUE would be small since only minimal amounts of sales gas to NUL from Judy Creek would otherwise have been delivered to Edmonton until push gas requirements for the miscible-flood scheme would be substantially reduced in the latter half of the study period. Esso estimated that the cost of ethane at the Dome/CUE plant would increase by less than 5 per cent if the proposal were approved.

Esso acknowledged discussions with Gulf Coast petrochemical producers regarding the export of ethane surplus to Alberta needs, but stated that any Judy Creek ethane which might be exported between 1984 and 1987 would not increase petrochemical capacity outside Alberta since these volumes would go to existing facilities under short-term arrangements.

5.2 Views of the Interveners

AEEPP argued that the proposal represents a component of a potential network of field extraction plants and that such a network would endanger the existing straddle plant system and Alberta petrochemical industry. AEEPP stated that the principal prerequisite for an Alberta petrochemical industry is the provision of a secure, long-term, economically-priced supply of ethane. Removal of the capability of the project to supply this feedstock would have an adverse impact on

the development of the olefins petrochemical industry in Alberta. AEEPP estimated that approval of the application would increase the cost of ethane from Dome/CUE by $6.5 million in 1985. AEEPP believed that this application should not be considered in isolation but as part of a larger ethane extraction system.

Shell expressed concern that approval of this facility without approval of a fractionator might result in increased removals of ethane from Alberta.

5.3 Views of the Board

The Board has no evidence before it that the proposed facility is part of a "network" and, in any case, believes that each application brought before it should be treated on the basis of an appraisal of that specific application. The impact of the Judy Creek proposed facility on the existing petrochemical industry in Alberta is, in the Board's view, significant only if it can be demonstrated that the petrochemical industry does not now, or in future, require the incremental volumes of ethane which would result from processing the Judy Creek gas at Judy Creek rather than Edmonton. The Board's most recent assessment of overall ethane supply and demand was published in the AGE III decision and is shown in Table 1 (Appendix II) supplemented by demand estimates for a recently applied-for fourth ethylene plant. It shows the volumes of ethane available from currently-utilized sources or those in the advanced planning stage will not be sufficient to meet likely petrochemical demands. Additionally, there will be demands for non-petrochemical uses such as miscible flooding which should be substantial if an attractive economic climate for enhanced recovery exists. These reasons would tend to suggest that the public interest would not be served if the incremental volumes of ethane which could result at Judy Creek were not recovered, especially since these incremental volumes would be less costly than similar volumes available elsewhere in the province where firm plans for field extraction do not presently exist. However, notwithstanding the Board's earlier assessment of ethane supply and demand, recent developments in the world petrochemical scene suggest that ethane demands for petrochemical purposes in Alberta may be less than previously forecast. If such were the case, the public interest features of recovering the extra volumes at Judy Creek by constructing the applied-for facilities would be reduced.

As stated earlier, the Board acknowledges that the cost of ethane from existing facilities would modestly increase if the Judy Creek plant were constructed and ethane production at Edmonton remained lower than otherwise possible. However, the Board believes that this increase could be largely offset by the availability of the lower-cost incremental volumes compared to those volumes available from other sources should they be required.

The Board notes that there may be plans to export some of the ethane recovered at Judy Creek to the petrochemical industry in the United

States. The removal of such volumes from the province would be subject to an application under the Gas Resources Preservation Act and presumably would not be allowed if judged injurious to the Alberta petrochemical industry.

In summary, the Board does not believe that the impact on the Alberta petrochemical industry resulting from approval of the applied-for facilities would be great enough to warrant denial. At the same time, it recognizes that if demand for ethane by the Alberta petrochemical industry turned out to be less than anticipated, the positive impact on the Alberta petrochemical industry referred to earlier in this section might not exist, and there could indeed be potential for modest negative impacts.

6 DEGREE OF UPGRADING

6.1 Views of the Applicant

The applicant stated that the entire ethane output from the proposed facility would be upgraded into ethylene in Alberta after 1986 at a plant it will construct. Ethane production over the 1984 to 1987 period would be made available to the existing Alberta petrochemical industry, utilized for miscible-flood schemes, or exported. Export volumes would be small and would not result in an expansion of ex-Alberta capacity to compete with the domestic petrochemical industry. Esso indicated it would give priority to the sale of ethane to the Alberta petrochemical industry even if the export price exceeded the domestic price. Over the life of the project, 80 per cent or more of the ethane would be sold to the Alberta petrochemical industry.

6.2 Views of the Interveners

Some interveners, notably AEEPP, expressed concern that the applicant would be exporting ethane to competing petrochemical manufacturers in the United States. They stated that the project could be delayed until 1986 and still meet the Alberta petrochemical industry's requirements.

6.3 Views of the Board

The Board is of the view that if markets for the product exist, there are significant benefits to upgrading at Judy Creek, but the degree of upgrading is a function of the incremental ethane recovered and the disposition of that ethane. The Board notes that Esso intends to give priority to the sale of ethane to the Alberta petrochemical industry.

The Board considers ethane extraction as upgrading of a resource. For the maximum incremental case the ethane upgraded from its alternative uses as fuel or miscible flood material would be some 6.8×10^6 m^3 over the proposed project life. The Board also recognizes an opportunity for further upgrading of ethane in the province.

For the minimum incremental case the ethane upgraded from its alternative uses would be some 3.9×10^6 m^3 and, again, opportunity for further upgrading of this resource in Alberta would exist.

Given the volume of incremental ethane recovered from the proposed facility the opportunity of upgrading the ethane into further petrochemical products is a significant benefit.

7 CONSERVATION AND ENVIRONMENTAL IMPACT

7.1 Views of the Applicant

Esso stated that the plant would be designed to be energy efficient and to have no adverse impact on the environment. Esso also indicated that a beneficial effect of its proposal would be ethane extraction from gas that is either consumed as fuel or injected to miscible recovery projects.

7.2 Views of the Interveners

None of the interveners seriously questioned the conservation and environmental impact aspects of the proposed facilities.

7.3 Views of the Board

If the Board were to approve the application, the proposed facilities would be constructed on land currently owned by Esso. The Board also notes that no increase in SO_2 emissions is applied for, and that all of Alberta Environment's concerns were satisfied in advance of the hearing. With respect to conservation aspects of Esso's proposal, the Board is satisfied that the proposed process would incorporate efficient up-to-date technology. In addition, a source of lean push gas for miscible flooding purposes would appear to be facilitated, and the stripped gas containing two per cent ethane would provide a leaner fuel gas for the Judy Creek plant and the enhanced recovery scheme, thus conserving ethane for petrochemical upgrading within Alberta or for miscible-flood solvent bank purposes.

The Board concludes that approval of the application would be in the public interest with respect to conservation and environmental impact.

8 OTHER PUBLIC INTEREST MATTERS

8.1 Impact on the Alberta Treasury

8.1.1 Views of the Applicant

Esso stated that it had not estimated the impact of its proposal on payments to the Alberta Treasury. It received confirmation from the

provincial government that the proposed facility would qualify for gas cost allowances and the ethane royalty rate would be in accordance with the Natural Gas Royalty Regulations. Esso indicated that presently no royalties are paid on gas or ethane consumed as fuel or used for miscible-flood schemes. As a result of its proposal, royalties would be paid on this ethane. Esso also noted that royalties would be paid on the additional gas produced to make up for the added shrinkage at Judy Creek.

8.1.2 Views of the Interveners

Dome/CUE estimated that approval of the application would decrease Esso's royalty payments to the Crown by approximately $12 million per year. This loss would be the result of the "change in the rules" respecting royalty treatment and receipt of the export price adjustment for ethane requested by Esso. It does not account for the applicant's request for gas cost allowance. Dome/CUE predicted a total annual loss to the treasury of $16.4 million.

8.1.3 Views of the Board

The Board recognizes that approval of the Esso proposal would have an impact on payments to the Alberta Treasury. Evaluation of relative impacts would measure total royalty payments by Esso with and without the proposed application as well as total royalty payments on gas from sources other than Judy Creek which feed the Dome/CUE straddle plant. A detailed comparison would be very complex and subject to a number of rulings by the Department of Energy and Natural Resources.

The Board has estimated that royalty payments by Esso to the Crown would decrease if the project were approved. Whether or not total payments to the Crown would decrease depends on assumptions about conditions that would prevail if the plant were not built and on other uncertainties. It is the Board's general view that no substantial change in total payments to the Crown would occur, regardless of the decision.

8.2 Proprietary Rights of Producers

8.2.1 Views of the Applicant

Esso stated that the ownership of the gas and its co-products was of prime importance and that disallowing an owner to maintain ownership of its gas and co-products for purposes of further handling and upgrading would not be in the overall public interest.

8.2.2 Views of the Interveners

Several interveners supported Esso's stance that the proprietary right of the producer should be maintained so that the producer would have an equal opportunity to take part in the petrochemical business.

There were an approximately equal number of opposing interveners who downplayed the role of proprietary rights of the producer, stating that, in the overall interest of the province, its citizens would be better served by maintaining the status quo with respect to locations of ethane extraction and the lower costs associated with recovering ethane at those locations.

8.2.3 Views of the Board

The Board considers that, subject to other aspects of the public interest, a holder of mineral rights should have the opportunity to recover as a separate product the ethane contained in the oil and gas produced pursuant to its arrangements for minerals. The Board emphasizes, however, that this matter is only one element of the public interest and must be considered with all other issues deemed important to the public interest.

8.3 Prospects for Increasing Production of Shut-in Gas

Since incremental ethane would be recovered at Judy Creek if the facilities proceed, the Board believes that approval of the application would result in an increase in production of gas to make up for the additional shrinkage.

8.4 Enhanced Recovery of Oil in the Judy Creek Area

The Board believes it appropriate to keep in mind the potential for enhanced recovery schemes in the Judy Creek area. Approval of the proposed deep-cut facility in the area might encourage oil producers to proceed with additional enhanced recovery schemes.

8.5 Impact on NUL Customers

8.5.1 Views of the Applicant

Esso presented no evidence with respect to the impact of the proposed project on NUL customers.

8.5.2 Views of the Interveners

NUL stated that the loss of Judy Creek gas to the Edmonton straddle plant would result in a revenue shortfall of \$0.5 to \$0.75 million per

year and that this revenue shortfall would have to be made up by other customers. NUL indicated that if make up gas for the Judy Creek volumes came from the western side of the province to the Edmonton plant, the shortfall would be reduced by 10 to 15 per cent.

8.5.3 Views of the Board

The Board believes that the effect of the scheme on NUL customers will be different for the maximum and minimum cases. In both cases, however, the Board is of the view that the impact on gas rates to NUL customers would not be substantial and, in any case, would result from business decisions by NUL.

9 DISCUSSION AND CONCLUSIONS

The foregoing assessment of the public interest has led the Board to conclude that if the assumptions underlying the maximum incremental ethane recovery case prevail in future, the application of Esso should be approved. The Esso scheme would then provide substantially larger volumes of ethane at a lower cost than the cost at which similar volumes could be made available from the processing of a portion of the Judy Creek gas at Edmonton while making up the difference from alternative sources which are not now producing ethane or where no plans exist to recover ethane in the near future. On this assumption, the volumes which could be recovered at Edmonton are such a small portion of the total recoverable at Judy Creek that the Judy Creek facilities should be built. Not only would there be additional volumes of ethane available at lower cost, but the proposal would also involve additional upgrading of resources; have no significant unfavourable impact on the Alberta treasury; would incorporate a reasonable degree of conservation; and would result in an acceptable level of impact on the environment. All of these factors would combine to make approval of the scheme in the Alberta public interest if it is assumed that the maximum incremental recovery case is the appropriate basis from which to arrive at a decision.

If the assumptions underlying the minimum incremental recovery case would prevail in future, the Board's assessment again suggests that the Esso application should be approved. This is primarily for the same reasons listed under the maximum incremental recovery case, but in this instance the incremental volume of ethane that could be produced by constructing the Judy Creek facilities would be considerably less. Put in another sense, much of the same volume of ethane could be recovered at Edmonton at a cost which would be less than the cost of recovery at Judy Creek. For this minimum incremental recovery case, the advantages

of constructing at Judy Creek are thus reduced; and if the demand for ethane in Alberta proves to be less than anticipated, there may be no justification for building the facilities at Judy Creek.

The Board's assessment of the public interest, particularly as it relates to the supply and cost of ethane and the resulting impact on the petrochemical industry, indicates that if the demand for ethane in Alberta is very high the application should be approved, notwithstanding which base case prevails. However, if the demand is not as great as generally expected there could be some advantage in not constructing facilities at Judy Creek but rather in recovering most of the ethane by processing the Judy Creek gas at Edmonton. Such a situation could only occur if the necessary business arrangements were put in place to facilitate recovery of most of the Judy Creek ethane at the existing Edmonton plant. These business arrangements would involve producers of the Judy Creek gas, transporters of the gas, and owners of the existing Edmonton straddle plant.

Having in mind the above conclusions respecting public interest, the Board believes that denial of the Esso application would be inappropriate. In taking this position, the Board has regard for all aspects of the public interest, including the fact that approval would allow producers to recover ethane as a specification product from their own leases if they choose to do so. The Board is thus prepared to approve the application for the Judy Creek facilities, but recognizes that if ethane requirements in Alberta do not grow as rapidly as was earlier expected, one of the primary reasons for approval and construction of the facilities loses some of its importance. If the volumes of ethane which would be recovered at Judy Creek were to be, in whole or part, surplus to Alberta's needs and thus had to be removed from the province, it would be essential that they go into markets consistent with the Alberta public interest. Presumably, the requirement for a removal permit for ethane would ensure this.

Bearing the above situation in mind, the Board is prepared to issue an approval, but nevertheless urges Esso to carefully examine the situation prior to commencing actual construction of the facilities and, if appropriate, to consider the possibility of negotiating arrangements with others for processing of Judy Creek gas at the existing Edmonton straddle plant.

10 DECISION

Having considered all of the evidence, the Board finds that the proposed facilities are in the public interest and is prepared to approve the application subject to receipt of the necessary Ministerial Approval.

DATED at Calgary, Alberta on 29 March 1982.

ENERGY RESOURCES CONSERVATION BOARD

N. Berkowitz, P.Eng.
Vice Chairman

G. J. DeSorcy, P.Eng.
Vice Chairman

F. J. Mink, P.Eng.
Acting Board Member

APPENDIX I

BASIS FOR CALCULATION OF MAXIMUM AND MINIMUM INCREMENTAL ETHANE RECOVERY CASES

The ethane recovery factor at the proposed Judy Creek deep-cut facility would be 92.52 per cent as submitted by Esso. The disposition of the lean residue gas from the proposed deep-cut plant is assumed to be as submitted by Esso in Exhibit 10 with the exception that until 1989 the Board finds there would be no lean residue gas remaining after taking fuel and miscible flood needs into account: hence there is a deficiency that must be made up from another source. The Board has chosen to assume back-flowing of Carson Creek gas as the most likely source to make up this temporary deficiency.

The Board has concluded from the evidence that in 1989 and thereafter, there is excess lean residue gas which could leave the Judy Creek area but that, if the Judy Creek deep-cut plant existed, NUL's contract would not be renewed. Rather, it is assumed that NUL would attempt to bring in richer gas from areas such as Rimbey, Golden Spike, Paddle River, and Pembina. (Ethane content of that gas: 7.4 per cent. Recovery factor for 7.4 per cent gas assumed to be 90 per cent as submitted by Dome/CUE.)

Regarding the Swan Hills South miscible-flood scheme, the injection rates would be 2.8×10^6 m^3/d until 1988 and 0.7×10^6 m^3/d thereafter as submitted by Esso in Exhibit 11. The source of this gas is assumed to be lean Judy Creek gas to the extent it is available, supplemented by Carson Creek gas. Evidence indicated that 2.8×10^6 m^3/d of push gas would be needed as early as April 1982. So not only is there a deficiency of gas to supply to NUL as noted above, but also there may not be enough to supply the push gas and fuel needs in the Judy Creek area; therefore there would be a need for back-flowing from the Carson Creek area.

There are two baselines to which the above scenario is compared, should the deep-cut facility not be installed, and these baselines result in the maximum and the minimum incremental ethane recovery cases.

The baseline for the maximum incremental case is:

1. The flow rates of the ethane-rich Judy Creek Gas routed to Edmonton via NUL's pipeline would range from almost zero to 0.4×10^6 m^3/d during the 1984-1988 period, thereafter increasing to the capacity of NUL's line and reducing to 0.9×10^6 m^3/d in the year 2000, as submitted by Esso in Exhibit 11. The remainder of NUL's needs would be supplied by gas from other areas.

2. The ethane content of the rich Judy Creek residue gas would range from a high of 19.8 per cent in 1985 to a low of 13.0 per cent in the year 2000 as submitted by Esso at page 141 of the hearing transcript.

3. The recovery factors for ethane at the Dome/CUE plant would be 96 per cent for the Judy Creek gas and 90 per cent for lower-ethane-content gas averaging 7.4 per cent ethane as submitted by Dome/CUE.

4. The flow rates of the ethane-rich Judy Creek gas routed to to the Swan Hills South miscible-flood scheme would be 2.8 x 10^6 m^3/d until 1988 and 0.7 x 10^6 m^3/d thereafter, as submitted by Esso in Exhibit 11.

5. The permanent loss of ethane used in the enhanced recovery scheme would be 50 per cent as submitted by Esso.

The baseline for the minimum incremental case is:

1. The capacity of NUL's pipeline system would be expanded as proposed by Dome/CUE and NUL to accommodate all of the rich Judy Creek residue gas. This gas would be processed at the Dome/CUE plant and would result in a reduction in the amount of gas brought in from other areas when compared to the amount of other gas that would be needed in the Edmonton area should the Judy Creek deep-cut facility be built and the bulk of its resulting lean gas be retained in the Judy Creek area for miscible-flood scheme push gas purposes.

2. As in (2) above the ethane contents of the rich Judy Creek residue gas would be those submitted by Esso.

3. As in (3) above the recovery factors for ethane at the Dome/CUE plant would be those submitted by Dome/CUE.

4. As in (4) above the flow rates of gas routed to the Swan Hills South miscible-flood scheme would be those submitted by Esso. The ethane content of that gas would be 3 per cent as submitted by NUL as representative of recent analyses of gas routed through the NOVA pipeline running southward from the Marten Hills area.

5. As in (5) above the permanent loss of ethane used in the enhanced recovery scheme would be 50 per cent as submitted by Esso.

APPENDIX II

TABLE 1 POTENTIAL ETHANE[a] SUPPLY AND DEMAND

	POTENTIAL ETHANE SUPPLY[b] m^3/d		POTENTIAL PETROCHEMICAL DEMAND FOR ETHANE[c] m^3/d		
	Potential Ethane From Gas	Potential Ethane From Syn. Crude Oil	AGE I,II, III	ESSO,AEC, HCC	TOTAL DEMAND
1984	21 610	870	9 220	-	9 220
1985	29 330	1 740	14 750	-	14 750
1986	29 320	1 740	20 130	-	20 130
1987	29 260	2 460	21 290	4 180	25 470
1988	28 660	3 420	21 530	6 120	27 650
1989	27 720	4 320	21 530	6 650	28 180
1990	26 820	4 860	21 530	7 260	28 890
1991	26 370	5 340	21 530	7 640	29 170
1992	25 800	5 820	21 530	7 640	29 170
1993	25 140	6 300	21 530	7 640	29 170
1994	24 490	6 780	21 530	7 640	29 170
1995	23 760	7 260	21 530	7 640	29 170
1996	23 450	7 740	21 530	7 640	29 170
1997	23 590	8 220	21 530	7 640	29 170
1998	23 870	8 700	21 530	7 640	29 170
1999	24 460	9 180	21 530	7 640	29 170
2000	23 780	9 660	21 530	7 640	29 170

a Industrial Grade Ethane.

b From Decision 81-10. (Excludes any ethane to be recovered from miscible-flood schemes.)

c Maximum annual permitted or applied-for demand expressed on a daily basis. (Excludes actual and potential demand for ethane as a component of miscible-flood schemes and approved volumes of ethane in existing removal permits.)

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

ESSO RESOURCES CANADA LIMITED
QUIRK CREEK GAS PROCESSING PLANT

Decision 82-12
Application 810520

CONTENTS PAGE

1 INTRODUCTION

1.1 Application and Hearing

Esso Resources Canada Limited applied, pursuant to section 38 of The Oil and Gas Conservation Act[1], for approval to utilize spare plant capacity to process sour gas reserves from the Moose and Whiskey Fields at its Quirk Creek gas processing plant located in the south half of section 4, township 21, range 4, west of the 5th meridian. The approved maximum raw gas inlet rate of 2.536×10^6 cubic metres per day (m^3/d) would not be increased, and a maximum of 1.928×10^6 m^3/d of sales gas, 620 m^3/d of LPG mix, and 295 tonnes per day (t/d) of sulphur would be recovered.

Esso proposed to increase its quarterly sulphur recovery efficiency from the currently-approved level of 95.5 per cent to 96.5 per cent and to decrease its maximum permitted sulphur dioxide (SO_2) emission rate from 27.6 t/d (13.8 t/d of sulphur) to 22.6 t/d (11.3 t/d of sulphur). The SO_2 would be emitted to the atmosphere through the existing 107-metre high incinerator stack.

The application was considered at a public hearing in Calgary on 4 to 6 November, 23 to 26 November, 14 to 18 December 1981, and 5 and 6 January 1982, with V. Millard, N. Strom, P.Eng., and R. G. Evans, P.Eng., sitting. Immediately after the conclusion of the hearing of Application 810520, the Board heard applications by Shell Canada Resources Limited (Shell) for proposed pipelines and related facilities to connect the Moose and Whiskey Fields to the Quirk Creek plant. The pipeline applications are reported on in detail in ERCB Report 82-E[2] which is summarized in section 1.3. The attached figure shows the Quirk Creek and other plants in the area and certain major features of the area.

Appendix A is a list of those who appeared at the hearing. Shell intervened for the purpose of cross-examination and argument only.

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1 Now Section 26 of the Oil and Gas Conservation Act, (RSA 1980, c. 0-5).

2 Energy Resources Conservation Board, 1982. Shell Proposed Moose and Whiskey Pipelines and Related Facilities - Kananaskis Area. ERCB Report 82-E. Calgary, Alberta.

1.2 Background

Approval to construct the Quirk Creek plant was granted by the Board in 1969. The plant was originally designed to process 2.254 x 10^6 m^3/d of raw gas for the recovery of sales gas, LPG mix, and 94.0 per cent of the sulphur contained in the inlet feed. The approval was subsequently amended, increasing the plant capacity to 2.536 x 10^6 m^3/d in order to meet Esso's sales gas contract. The plant consistently achieved or exceeded a 95.0 per cent sulphur recovery efficiency as required by the guidelines in effect at the time[3]. In 1974, the approval was amended to require a sulphur recovery efficiency of 95.5 per cent and Esso has generally met or exceeded this level to the present date.

1.3 Decision on the Shell Pipeline Applications

In ERCB Report 82-E, the Board indicated that, because of public safety considerations set out in the report, the production of the Moose Field reserves as applied for, would not be compatible with the recreation program planned by the Kananaskis Country Interdepartmental Committee. Accordingly, the Board denied Shell's pipeline applications insofar as they related to Moose Field reserves. It follows that there is no need to rule on Esso's plant application insofar as the Moose Field reserves are concerned. However, the Board believes that, having regard for the possibility of tying in Whiskey Field reserves and to certain of the environmental evidence presented at the Quirk Creek hearing, the Board must consider the appropriateness of the currently-approved sulphur recovery level and other aspects of operations at the Quirk Creek plant. Section 3 of this report, which defines the issues with which the Board must deal, reflects this thinking.

2 PRELIMINARY CONSIDERATIONS RESPECTING THE ESSO APPLICATION

In this section, the Board deals with some preliminary matters prior to defining the issues.

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3 In accordance with IL 71-29 (Energy Resources Conservation Board, 1971 <u>Sulphur Recovery Requirements Gas Processing Operations.</u> ERCB Informational Letter IL 71-29. Calgary, Alberta).

Purpose and Intent of Legislation

Counsel for Ms. Hanen, in closing argument, referred the Board to, inter alia, two sections of the Board's legislation - section 4(f)[4] of the Oil and Gas Conservation Act and section 2 (d) of the Energy Resources Conservation Act[5], each being one of several "purposes provisions" of the respective Acts. Those sections read as follows:

> "4. The purposes of this Act are . . .
>
> (f) to control pollution, above, at or below the surface in the drilling of wells and in operations for the production of oil, gas and crude bitumen and in other operations over which the Board has jurisdiction."
>
> "2. The purposes of this Act are . . .
>
> (d) to control pollution and ensure environment conservation in the exploration for, processing, development and transportation of the energy resources and energy."

In so doing, he submitted that the Board has a statutory duty to do everything possible to control pollution without regard to the cost of the same. He argued that the Board must, as a condition of approval, require that pollution be controlled. He further submitted that the Board has the duty to make certain that pollution is controlled, without regard to economics, to the least possible amount consistent with the best available technology from time to time.

Counsel for Esso, in response to the foregoing argument, stated that it appeared that the basis for the suggestion that pollution should be controlled without regard to economics, is that in portions of the legislation and regulations cited by counsel for Hanen and dealing with pollution control there is no express reference to economics, whereas there are such references in certain other sections. Counsel for Esso went on to set out his position on two fundamental principles of statutory interpretation. Firstly, he submitted that legislation must be interpreted in accordance with its legislative aims and objectives, and in such a way as to avoid an absurdity. Secondly, he submitted that it is a fundamental doctrine of statutory interpretation that provisions of a statute must be interpreted, so far as is possible, to avoid conflicts between and among them. In this matter, he concluded by saying that if

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4 Previously section 5(e) of The Oil and Gas Conservation Act (RSA 1970, c. 267).

5 Previously The Energy Resources Conservation Act (RSA 1971, c. 30).

there would be a clear conflict with the Board's mandate set forth in section 4(c)[6] of the Oil and Gas Conservation Act, which obligates the Board "to provide for the economic, orderly and efficient development in the public interest of the oil, gas and crude bitumen resources in Alberta". He submitted that the argument put forth by counsel for Hanen violates these rules of statutory interpretation.

The Board believes that, in discharging its duties under the Energy Resources Conservation Act and the Oil and Gas Conservation Act, it must have regard for all the purposes of the respective Acts, insofar as they are relevant to the application before the Board and insofar as they are not inconsistent with each other. The Board takes note of the wording of section 4(c) of the Oil and Gas Conservation Act which requires the Board to provide for the economic, orderly, and efficient development in the public interest of the energy resources of Alberta. The Board is of the opinion that this subsection must be read together with section 4(f) of the Oil and Gas Conservation Act and section 2(d) of the Energy Resources Conservation Act, and that accordingly, the Board must, in looking at the purposes of the legislation together, have regard for the economics as they affect the application.

In regard to the submission of counsel for Hanen that the Board has a duty to make certain that pollution is controlled, without regard to economics, to the least possible amount consistent with the best available technology from time to time, the Board takes note that in section 4(f) of the Oil and Gas Conservation Act and in section 2(d) of the Energy Resources Conservation Act, the words "control pollution" are used, as may be contrasted to the words "prevent pollution". The Board considers the words "control pollution", as used by the Legislature of Alberta, to be significant. The Board believes that if the Legislature had intended the Board to prevent pollution, then it would have used such express words.

In summary, the Board concludes that the legislation directs the Board to control or limit pollution. The degree of limitation would be influenced by various considerations including economics. It follows that the "best available technology" is not necessarily the standard, and indeed, the term "best practical technology" is one compatible with the legislation. However, in particular instances and when warranted, the test might well be "best available technology".

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6 Previously section 5(b.1) of The Oil and Gas Conservation Act (RSA 1970, c. 267).

The Board recognizes that, with respect to the current application, it must operate within the existing legislative scheme at the time of the hearing of an application. In addition, the Board will, where policies and guidelines for pollution control standards exist, have regard for those policies and guidelines, but in so doing, the Board will consider the appropriateness of such policies and guidelines in each case before it. In other words, the Board, in assessing each application on its own merits, and after considering all the evidence in that regard, will decide whether there is some specific reason (ie. economics, environmental impact, public interest) directly related to the situation which would warrant the application of more stringent or less stringent standards in that case.

<u>Nature of the Evidence and Closing Argument</u>

Much of the evidence and closing argument presented by the interveners at the hearing was not directly related to the subject application, but dealt with broad and general matters such as the adequacy of current Alberta standards and policies for sour gas operations, the potential environmental impact of emissions from sour gas plants, the potential for emission from sour gas plants of certain substances termed by the interveners as "trace poisons and carcinogens", and other matters. The Board believes that it must assess the subject application on the basis of the evidence which is directly related to it, and the existing standards and policies. It recognizes, however, that the interveners presented useful evidence respecting sour gas operations in general in the Province and that the Lieutenant Governor in Council should be advised of that evidence. Accordingly, the Board plans to present its views separately on the more general evidence.[7]

<u>Other Matters</u>

The Board's review of closing arguments disclosed three comments made by counsel for Hanen, which are set out as follows:

1. <u>Page 21</u>

   "Thereafter, the Board heard sixteen witnesses (not including the Board itself - <u>inter alia,</u> TR 1359-1363, in conjunction with Exhibit No. 53 and No. 54!!!)."

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7 Energy Resources Conservation Board, 1982. <u>Sour-Gas Processing in Alberta</u>. ERCB Report 82-D. Calgary, Alberta.

2. Page 12

"Additionally, Mr. Fred Solterman was prevented by the Board from even attending to have his expertise as a farmer and a plant operator ruled upon (TR inter alia, 1581/23-1617/15) the result is that valuable independent evidence is not before the Board as it relates to specific consequences to farming of and the environmental impact from variable plant operational practices in the industry."

3. Page 71

"Specific evidence with respect to the operational handling and resulting farm effects of sulphur dust and sulphur melt, was prevented from being brought before the Board as Mr. Solterman was not allowed to testify."

Regarding the first comment, the Board is uncertain as to how to interpret the statement, but assumes it was intended to suggest that the Board was presenting evidence. Before commenting on that statement the Board believes it is significant that Mr. Rooke provided only a portion of the transcript reference to Exhibits 53 and 54. The reference to these exhibits actually commences on TR 1239 with a question by Mr. Rooke.

1. Page 1239 - line 14

Mr. Rooke: "......Perhaps before the break I could raise one question. I guess it goes to the equality of information and interveners and other parties here, and I don't know if it's proper that I should raise it but perhaps I can do so now while it's on my mind. You, sir, made reference to certain numbers of correlation of data of emissions between '63 to '66, '66 to '69, and then a decrease since that time, and one of the questions was with respect to the effect of the recommendation No. 21 from the Board's records, and I don't know if that's information that is of the basis of your personal work and study, sir, or if there is some information in an organized form before the Board that would be of assistance to the proceedings if made available to all parties."

2. Page 1241 - line 19

Mr. Rooke: "Perhaps I should be clear, Mr. Chairman, I'm not seeking to take your personal research and have it made part of the record. What I am concerned about is sometimes there is records that are available through the Board that you gentlemen and these people would be aware of that we're not aware of that may be relevant."

The Board believes that it is clear from the record that Exhibits 53 and 54 were not entered in the proceeding for the purpose of presenting evidence. At page 1246 of the transcript, the Chairman indicated on the record that those exhibits were prepared for the purpose of discussing the Acid Rain Subcommittee's Recommendation 21. Indeed, it is obvious from a review contained therein they represented information in the public domain and assumptions made by the author for purposes of obtaining answers to hypothetical questions. The tables contained in those exhibits were compiled to place before particular witnesses a detailed scenario in order to facilitate questioning in that regard.

The Board was quite amazed to see Mr. Rooke's comment, since it was he who asked for the material to be made available.

With regard to the second and third comments, the Board is astounded at these statements. Not only are they factually incorrect, but they indicate a complete disregard for the Board's adjudicative position. The Board would like to make two things perfectly clear:

(i) it is for counsel in a proceeding to argue the relevancy of evidence, and

(ii) it is for the Board, in its capacity as established by the Energy Resources Conservation Act and related Acts, to rule on the relevancy and admissibility of evidence.

In this case, the Board made a ruling; it did not prevent the presentation of evidence but rather ruled, after hearing the arguments of all counsel that <u>some</u> of the evidence that Mr. Solterman planned to present was not relevant. With respect to the remaining evidence, it indicated that "the Board is prepared to receive this evidence" (TR 1614), but Mr. Rooke chose not to present Mr. Solterman or the evidence.

3 ISSUES

Having regard for its decision to deny Shell's pipeline applications insofar as they relate to the Moose Field, and its intention to deal with general environmental concerns not directly related to Esso's application in a separate general report, the Board believes that the issues respecting the Esso Quirk Creek plant application with which it must deal are:

- the processing of Whiskey Field reserves at the Quirk Creek plant,
- the adequacy of the emission and other monitoring and reporting requirements for the plant,

- o whether or not the plant is operating satisfactorily in terms of energy resource and environmental conservation, and environmental impact,
- o the appropriateness of the currently-approved sulphur recovery level for the Quirk Creek plant, and the feasibility of 100 per cent sulphur recovery, and
- o the feasibility of injection of waste gases from the plant.

4 THE PROCESSING OF WHISKEY FIELD RESERVES AT THE QUIRK CREEK PLANT

Shell estimated the raw gas reserves for the Whiskey Field to be in the order of 1288 x 10^6 m^3. Analysis of the gas from the Whiskey well in Lsd 6-2-22-5 W5M indicated an hydrogen sulphide (H_2S) concentration of about 7.3 per cent. Shell submitted that the well could produce 110 x 10^3 m^3/d of raw gas at a wellhead pressure of 5000 kilopascals. However, Shell stated that the Whiskey reserves could only be developed through the sharing of costs and benefits associated with the development of the Moose reserves, and that a stand-alone Whiskey development would not likely proceed.

Ms. Hanen stated that the Quirk Creek plant is the most reasonable location for the processing of Whiskey gas and that there are no major environmental concerns related to such a scheme. She concluded by stating that, although she was not opposed in general terms to the processing of Whiskey Field reserves at the Quirk Creek plant, she presumed that any pipeline route changes necessary to tie-in the Whiskey well would likely be the subject of a future hearing.

Although Mr. Russell did not specifically address the possibility of only Whiskey Field reserves being processed at Quirk Creek, he expressed concern that the proposed pipeline route from the Whiskey well to Esso's plant would cross a "Critical Wildlife Zone".

The Board notes the comments of the interveners and has reviewed the possibility of processing Whiskey Field reserves at the Quirk Creek plant. The Board, in principle, accepts this possibility and further believes that such a plan would be prudent since it would result in some increased recovery of the Quirk Creek reserves. The Board notes Shell's evidence that a stand-alone Whiskey development likely would not proceed, and while it is prepared to allow processing of Whiskey reserves at the Quirk Creek plant, new applications would be required.

5 THE ADEQUACY OF THE EMISSION AND OTHER MONITORING AND REPORTING REQUIREMENTS FOR THE PLANT

5.1 Applicant's Views

With respect to air pollution monitoring, Esso testified that since the Quirk Creek plant went on-stream in 1971, it had utilized a three-tiered approach by measuring incinerator stack emission rates, ambient air quality, and certain environmental indicators which may be associated with air pollution effects. Esso stated that it has complied with all the monitoring requirements of its ERCB approval and those of the Clean Air and Clean Water Act licences issued by Alberta Environment. The applicant stated that it is required to monitor SO_2 concentration, volume flow rate, temperature, and oxygen content in stack gas emissions and to conduct stack surveys at least twice per year. Additionally, the applicant maintains sixteen total sulphation and H_2S exposure cylinders in a network around the plant and operates a continuous-air-monitoring trailer with automated instrumentation, to measure wind speed and direction, H_2S, and SO_2 ground-level concentration. Esso added that, since 1980, it has been required to obtain a minimum of six soil samples annually and to have the soil acidity or alkalinity (pH) measured, and buffering capacity of them determined.

Esso submitted that, in addition to its mandatory monitoring requirements, it has also undertaken numerous supplementary monitoring programs including aerial infra-red photography of the Quirk Creek area for the years 1970-75 and 1977, the establishment of corrosion stations to assess annually various metal samples, and annual soil and vegetation analyses to determine absolute sulphur levels and possible trends in sulphur concentration. Esso indicated that it intended to conduct additional aerial infra-red photography during 1982. The applicant stated that it had performed environmental noise surveys on two occasions to ensure that ERCB guidelines were being met. Additionally, Esso had commissioned consultants to obtain base-line environmental data prior to the plant start-up. Two surveys were conducted in 1969 and 1970 to provide data on total sulphation and H_2S levels, sulphur content of soil, sulphur content of vegetation, and surface water quality analyses.

Esso also stated that, although research clearly indicates that precipitation in Alberta is not acidic, it had requested Alberta Environment to locate a precipitation monitoring device downwind of its Quirk Creek plant in order to establish whether or not it is contributing to a local acid-rain problem. Furthermore, Esso indicated that because of the local issues and concerns raised at the hearing, it proposed to meet with local residents to discuss the establishment of a Quirk Creek environmental quality committee. Esso recommended that the committee be comprised of local residents, plant representatives, and possibly ERCB and Alberta Environment staff, and that the committee would have to first agree upon the method and type of studies required to investigate local concerns.

5.2 Interveners' Views

The interveners expressed serious concerns about the adequacy of the emission and other monitoring requirements for the plant in spite of the efforts made by the applicant to this end. Mr. Russell noted Esso's intention to conduct additional aerial infra-red photography of the Quirk Creek area in 1982. However, he requested that the Board direct Esso to make the information and results gathered from both the aerial infra-red photography and the acid-rain monitoring equipment available to area residents and the interveners.

Ms. Hanen recommended that, as conditions of continued operation, a detailed emergency plan for residents be required and that detailed monitoring of the Quirk Creek plant operations be carried out at regular intervals by an independent agency such as the Board or Alberta Environment, so that full and complete data of individual occurrences and long-term trends will be readily available on public record.

The recommended monitoring included soil pH, metal corrosion, water emission, water withdrawal from Threepoint Creek, noise, odour, acid rain, incinerator and flare stack effluent monitoring, blood and other testing of domestic animals, feed analysis, and aerial photography and interpretation every two years. She further recommended that local residents be allowed to have their soil, land, and air included in such monitoring and testing, should they wish to do so. Ms. Hanen also asked that the Board order Esso to fund independent monitoring of trace poisons and carcinogens known to be found in conjunction with or suspected from the production, processing, and transmission of hydrocarbons.

5.3 Board's Views

The Board has considered the adequacy of monitoring and reporting for the Quirk Creek plant by comparing the requirements currently in place for the plant with the conditions recommended by Ms. Hanen as requirements for the continued operation of the plant.

With respect to a <u>detailed emergency plan</u>, the Board notes that Esso has had such a plan for the Quirk Creek operation since 1972 although the Oil and Gas Conservation Regulations were not amended to require one until 1977. The plan is available for public examination either through Esso or through the Board's Calgary office or its Turner Valley Area Office. The plan is updated regularly and includes detailed procedures for various circumstances, contact lists for key personnel and area residents, and other critical information. Thus, the Board believes that this recommendation has been met for some time.

With respect to Ms. Hanen's recommendations relating to water withdrawal from Threepoint Creek and alternative sources of water supply for the Quirk Creek plant, the Board notes that the matter is administered by Alberta Environment through the Water Resources Act and that a licence for the use of the water from the creek has been granted to Esso. There appears to be no evidence that the terms of this licence have been violated or that the quantities being diverted are causing problems.

With respect to Ms. Hanen's recommendations regarding emission monitoring and reporting requirements and surveillance, the Board notes that to some degree, it appears that the interveners were not aware of the surveillance measures already required of the applicant and the Board believes it appropriate to outline some of the surveillance responsibilities of both the Board and Alberta Environment. The Board requires that a monthly sulphur balance report be submitted to show, for each operating day, the sulphur contained in the raw gas processed and the sulphur recovered as elemental sulphur product or emitted, along with a calculation of the sulphur recovery level. The Board compares the reports of actual H_2S inlet, SO_2 emissions, and sulphur recovery level to the approved levels. Additionally, the Board staff conduct periodic measurement instrument calibration checks. The Board also reviews continuous stack emission monitor (CSEM) downtime and measurement differences for acceptability. Where approval conditions are not being met or where CSEM downtime or measurement differences are not within acceptable tolerances, the operator is required to advise the Board what steps have been or will be taken to prevent problem recurrences. In this manner the requirements for a daily sulphur balance are fulfilled.

The results of incinerator stack surveys required at least twice per year for the Quirk Creek plant are used to confirm the accuracy of the CSEM results. If these surveys do not confirm the CSEM data, more frequent surveys are made to determine the source of the discrepancy. Any problems respecting the basic data for the sulphur balance reports can be thereby rectified through alteration to methods for obtaining analytical data or improving the operation of the CSEM itself. Thus, the Board believes that Ms. Hanen's concerns respecting the quality of information used for the preparation of sulphur balance reports have been addressed. While the daily sulphur balance report and CSEM monitoring includes the quantity of SO_2 but not H_2S, the semi-annual stack survey requirement includes analysis for H_2S. The presence and level of H_2S in the incinerator stack effluent would indicate incomplete conversion of H_2S to SO_2. The degree of conversion from H_2S to SO_2 would be reflected in the survey results and can be optimized by control of such factors as the fuel gas rate to the incinerator, the air to fuel ratio, and the incinerator effluent exit temperature. Proper control of these factors should ensure efficient conversion of H_2S to SO_2 such that the presence of H_2S in the incinerator effluent is negligible.

No evidence was provided which demonstrated the emission of trace poisons from the Quirk Creek plant, and accordingly the general matter of the need to perform analyses of incinerator and flare stack effluent for trace poisons at all sour gas plants is discussed in the Board's general report. However, in connection with the general matter of the potential for emission of trace poisons, the Board intends to have detailed analyses conducted by an independent laboratory on incinerator stack gases at a sampling of Alberta plants, including the Quirk Creek plant, to determine the presence or absence of such material. The results of these analyses will be made available to the public.

Soil pH, aqueous emissions, and ambient SO_2, H_2S, and total sulphation monitoring is required and thus, this recommendation is met. Although Esso conducts corrosion monitoring, this is not a requirement. With respect to noise and odour monitoring, these matters are dealt with on an incident or complaint basis and the Board does not believe that any special conditions need to be imposed. On the matter of forage feed analysis, the Board has no jurisdiction to require it, but notes that such a service is available through Alberta Agriculture. Similarly, the Board has no jurisdiction respecting Ms. Hanen's recommendation for funding of blood and other testing of domestic animals. Finally, with respect to aerial infra-red photography and interpretation, the Board notes that, although it is not a requirement, Esso intends to carry out a program in 1982, and to that extent, the recommendation is met. Whether or not further programs are conducted in future years will likely depend on the results of the 1982 program. The Board does not believe that any of the evidence demonstrates the need for aerial infra-red photography as a condition of continued operation of the plant.

On the question of independent monitoring, the Board believes that it would be expensive and would require a great deal of additional manpower. In addition, the Board believes that witnessing of tests, inspection, and surveillance conducted by the Board and Alberta Environment gives independent cross-checking and that further expansion of this is not required.

Ms. Hanen's recommendation respecting the continuation of stack monitoring through independent agencies is met to the extent that the Board staff witnesses the regular stack surveys. The Board considers that the recommendations for independent total sulphation, H_2S, and other ambient air monitoring are matters for Alberta Environment's consideration. With respect to Quirk Creek, there was not sufficient evidence to convince the Board that special circumstances or problems exist and it believes that normal surveillance by the Board and Alberta Environment should be sufficient to ensure proper results.

On the matter of soil and other monitoring specifically on Ms. Hanen's and other local residents' lands, the Board notes that off-site monitoring is required by Alberta Environment and is designed to take place in areas where any effect would be first noticed, which may include local residents' lands. However, the Board notes and strongly endorses Esso's intention to meet with local residents to discuss the establishment of a Quirk Creek environmental quality committee on local issues and concerns and to hold an annual meeting for local residents. The Board believes that such a committee may be an appropriate vehicle to deal with this matter and would be an excellent opportunity for Esso to report to the local residents on the overall environmental matters relating to the plant, to discuss the contingency plans, and to receive suggestions for improvements. The Board believes that the plan should be available for public examination by local residents at the plant. With respect to the availability to the public of monitoring data, such data can be obtained from the Board and Alberta Environment, and although no formal procedures are established for the dissemination of it, the availability of such data was clearly demonstrated by the evidence filed at the hearing. Therefore, the Board believes that the availability of data is best left on an as-required basis for the present.

6 OPERATION OF THE PLANT

6.1 Applicant's Views

Esso indicated that the Quirk Creek plant, as with all other gas plants, is regulated by numerous government agencies and because of the complex nature of sour gas operations, no plant could point to a perfect record of compliance with every regulation. However, Esso stated that, for the most part, its plant's performance has been better than regulations require. With respect to compliance with the Clean Air Act, Esso testified that since 1978, the Quirk Creek facility had not exceeded 56 per cent of the annual SO_2 emission rate and with regard to H_2S, its sulphation readings had never exceeded 26 per cent of the "level of concern" set out in Alberta Environment Air Monitoring Directive AMD 80-2[8]. Esso stated that to a very significant extent, ambient air monitoring excursions had been recorded when prevailing winds had been toward the plant from the air monitoring trailer, thus clearly pointing to an H_2S source other than the plant itself. Esso testified that while practically all of the flaring and black smoke incidents had been reported, in fact none of them exceeded the 48 hours' duration for which reporting should be required under the provisions of Approval 2944.

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8 Alberta Environment, 1980. Air Monitoring Directive-Oil and Gas Industry. Alberta Environment Air Monitoring Directive AMD 80-2. Edmonton, Alberta.

With respect to water withdrawal from Threepoint Creek, Esso stated that it had complied fully with its licence requirements and that in the 10 years of operation, withdrawals had no detrimental effect on local water conditions. Esso contended that compliance with air and water quality standards should preclude measurable environmental damage and that its record showed much better than bare compliance with these standards.

With respect to energy resource conservation, Esso stated that on no occasion under the current Board approval had the plant exceeded its annual flaring allowance of 0.5 per cent of raw inlet gas. Additionally, the Quirk Creek plant had recovered sulphur in excess of the approval requirement of 95.5 per cent and had averaged about 96 per cent for the past four years. Esso concluded by stating that its "track record" with respect to compliance with standards and requirements was commendable and that after more than a decade of operations, no environmental damage had been caused or was likely to be caused by continuing operations at the present sulphur recovery level of 95.5 per cent. However, in the interest of energy resource conservation and in an effort to reach the highest practicable sulphur recovery level achievable with the existing plant, Esso proposed to increase its sulphur recovery efficiency to 96.5 per cent for the present application.

In response to questions at the hearing, Esso stated that, if the plant's main power supply from TransAlta Utilities Limited were interrupted for more than a few minutes, this would interrupt the operation of the plant such that it would be necessary to shut in the plant or to flare the raw gas until power could be restored. It stated that in the years 1980 and 1981, the plant had been shut in only once because of a lack of electrical power. It stated that it has generation facilities at the plant fully capable of running the instrumentation necessary to bring the plant down in a controlled fashion in the event of a power interruption.

Esso summarized by stating that its twelve years of data had confirmed the basis implicit in Alberta's air quality objectives; that is, if a plant consistently complies with these standards, as it had, no environment damage would occur.

6.2 Interveners' Views

Ms. Hanen, who lives adjacent to the Quirk Creek plant, outlined certain incidents, which she believed exemplified poor operating procedures at the plant. Her evidence included photographs of elemental sulphur in ditches and corrosion in a culvert that she believed was a result of acidic run-off from the Quirk Creek plant. She related personal experiences when she had been subjected to intense odours from the plant and instances of noise pollution. Additionally, Ms. Hanen expressed concern that Esso had exceeded its licensed maximum water withdrawal rate from Threepoint Creek and had diverted water in the summer months when the creek was very low.

Both Ms. Hanen and Mr. Russell commented on incidents of flaring and black smoke emissions from the Quirk Creek flare and incinerator stacks. Mr. Russell submitted several photographs of smoke emissions including one particular photograph which he believed showed that the flare stack had been struck by lightning which had resulted in the flare pilot being extinguished and ensuing heavy smoke emissions. Ms. Hanen stated that, while Esso may have operated within its permitted hydrocarbon flaring limit, it had clearly violated a number of standards imposed by the Board and the Department of the Environment. All the interveners agreed that incidents of flaring should be avoided even to the extent of shutting in the wells if necessary. Additionally, Ms. Hanen and Mr. Russell recommended that mitigating measures be taken to prevent the flare stack pilot from being extinguished.

Ms. Hanen submitted that the operational considerations, both current and future, were dependent upon the suitability of the design of the plant. She listed several areas which she perceived to represent design faults in the Quirk Creek plant, including the dependence of various key components on electricity from an unpredictable source (ie. power supply), the inability of the computer control system to provide a permanent record of operations and procedures, and the unreliability of the flare stack pilot and ignition system. Ms. Hanen suggested that Esso had recognized these design faults and for that reason had included some but not enough corrective modifications as part of its application. She recommended that the Board should require Esso to undertake these and other modifications as a condition of continued operation regardless of whether the application involving Moose and Whiskey gas were approved.

6.3 Board's Views

In considering whether or not the Quirk Creek plant is operating satisfactorily, the Board has taken the position that the existing standards are appropriate, unless special circumstances warrant the application of a restrictive standard. The Board does not believe the evidence indicates special circumstances, and therefore, has compared the operating data to the standards. The matter of sulphur recovery level is dealt with in Section 7 and the general matter of the adequacy of Alberta's standards for sulphur recovery and SO_2 emissions is dealt with in the Board's general sour gas report. In this section, the Board considers other environmental concerns including: flaring, black smoke, noise, odour, emissions of elemental sulphur, H_2S, water, and trace poisons.

With regard to <u>flaring of raw gas</u>, the Board is satisfied that the 0.5 per cent maximum limit for the plant is being met. Staying within this limit is important because it prevents avoidable waste of raw gas and sulphur and it reduces the potential for adverse environmental effects that might be caused by such flaring. On the other hand, while the flaring limit is

being met in terms of volume, the Board notes that most of the incidents which comprise the total flaring are of short duration. The Board believes that, depending on the volume of gas required to be flared, these short-duration incidents, particularly night-time occurrences are inclined to be given disproportionate significance by the casual observer because they are made obvious by the light contrast. As a matter of good operating practice, the Board expects operators to limit flaring to the minimum necessary both in terms of duration and frequency. For example, the Board agrees with Esso that under some circumstances it is better to flare until a plant operating problem is resolved rather than to shut the field in. If the plant upset is short term, less flaring would result than if the plant were shut in and had to be started up again. However, the Board generally agrees that there may be circumstances where the best practice would be to shut the plant in rather than continue flaring while trying to resolve the plant or field operational difficulty. Also, as an aesthetic measure, the Board would be prepared to restrict flaring to day-time hours for turnarounds or maintenance that can be done during daylight hours. Since prior notification of turnarounds is a condition of plant approvals, the Board would impose the restriction at the time the notification is made and approval of flaring for this purpose is sought. The Board notes that the amount of raw gas and fuel gas added to convert H_2S to SO_2 and provide thermal lift must be measured and reported.

On the matter of the power supply for the plant, the Board will pursue with Esso the need for and feasibility of a back-up power system. Finally, the Board has received no evidence to support the need for detailed consideration of methods used to prevent the flare stack from being extinguished. Indeed, the evidence indicates that such occurrences have been rare and that the flare stack has operated acceptably the majority of the time.

The emission of black smoke on a routine operating basis from oil and gas facilities is not permitted by the Board. When it does occur and the Board becomes aware of it through operator reports, resident complaints, or routine inspections by its field staff, the operator is required to satisfy the Board that steps have been or are being taken to prevent a recurrence. In the case of the Quirk Creek plant, black smoke related to flaring has been a problem in the past; however, the Board is satisfied that the required installation of a flare knock-out drum in 1980, to remove hydrocarbon liquids from the flare stream has substantially alleviated the problem.

With respect to noise, facilities are required to meet the Board's noise guidelines set out in ID 80-2[9]. The Board has not received any evidence that the plant or related facilities are operating in excess of the

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9 Energy Resources Conservation Board, 1980. Noise Control Guidelines ERCB Interim Directive ID 80-2. Calgary, Alberta.

guidelines. Complaints of excessive noise are followed up by the Board's field staff who measure the operating noise levels to ensure compliance with the guidelines.

With respect to odours, the Board's objective and expectation is that gas plants should operate without odours under normal operating conditions. Unusual operations or upsets, which may result in some odours, must be minimized, and the Board's field staff is prepared to respond immediately to any odour complaint. Odours are perhaps one of the most difficult nuisance factors for operators to control, as they may arise for a number of reasons including operating practices, how well equipment is maintained, and whether the equipment is at normal or upset conditions. With respect to Ms. Hanen's request that all odour emissions be restricted and reported to the Board, that is indeed the Board's policy. However, that does not mean there will not be odours from time to time. In many cases the operator would not be aware of all odour-causing incidents, particularly the small ones, although it should be able to anticipate the larger incidents that arise from unusual upset conditions. Reports of the larger incidents are made to the Board's area office; for the smaller incidents, the Board believes that they can best be handled on a complaint basis.

With respect to elemental sulphur, the Board's policy on emissions of sulphur dust is that it must not leave the plant site. Should there be an occurrence, the affected area must be cleaned up, and rehabilitated as necessary. This policy is also incorporated in the Board's approval of methods for sulphur block (stockpile) reclaiming. Generally speaking, the Board will not approve mechanical methods which result in sulphur dust problems but will approve most thermal melting methods. Since the Quirk Creek sulphur block is currently being reclaimed by an approved thermal method, it would appear that Ms. Hanen's request that "the existing bulk supply of sulphur be removed by melting process" is being met. On the other hand, her request that the sulphur "be degasified" does not appear necessary as there is no evidence that odours or ambient H_2S problems are resulting from the melting operation. With respect to the request that "no bulk sulphur be stored on the plant site but be removed in liquid form" the Board believes that it is a desirable one which also appears to be Esso's goal. However, while the storage of solid sulphur on a plant site has been prohibited in some cases, the Board believes that it is not a reasonable condition in this case and that it should depend on whether sulphur markets are such that sulphur would be removed in liquid form as it is produced.

With respect to H_2S emissions, these are not permitted to result in odours or the maximum ground-level concentration being exceeded. The ambient level of them is monitored and compared with standards set by Alberta Environment. Tail gas from the Quirk Creek plant's sulphur recovery unit is incinerated for the conversion of H_2S to SO_2. Sufficient fuel gas must be added to raw gas if it is to be flared to ensure similar conversion.

The monitoring data presented in evidence indicates that excursions involving H_2S have been infrequent. The Board is thus satisfied that no special conditions are necessary respecting the control of H_2S emissions.

With respect to water emissions, the Board notes Esso's evidence that there has been only one occasion since the plant commenced operations in which liquid has left the plant site in an uncontrolled fashion. In that case, the affected area was reclaimed. Thus, the Board sees no need for extraordinary conditions respecting control of water emissions.

7 SULPHUR RECOVERY

7.1 Applicant's Views

Esso pointed out that there was no expansion of process facilities associated with the present application. However, it recognized that, having regard for the life extension of the plant to the year 2005 if the Moose and Whiskey reserves were tied in, increased sulphur recovery efficiency would be a principle consideration in the determination of the application.

Esso's evidence with respect to sulphur recovery dealt mainly with a sulphur recovery level which it believed was appropriate to the applied-for scheme in which gas from the Moose and Whiskey Fields, in addition to the Quirk Creek Field, would be processed at the Quirk Creek plant. It stated that, based upon projected flow rates and H_2S inlet composition, it was prepared to guarantee a minimum efficiency of 96.5 per cent on a quarterly-average basis by using the existing 3-stage Claus plant, but this would require more frequent change-out of the catalyst, modifications related to feed-back and feed-forward control, hot gas bypass temperature control, and aerial cooling modifications. It stated that the capital cost of the modifications would be \$6 million (1981), including a small component for an additional inlet separator to handle Moose and Whiskey production.

Esso stated that the applied-for increase in efficiency met the intent of IL 80-24[10], which sets out new sulphur recovery guidelines, in that 96.5 per cent was equal to the weighted average of 95.5 per cent recovery of the Quirk Creek volumes, and 97.5 per cent recovery of the 175 t/d inlet sulphur rate from the Moose and Whiskey gas which would be required by IL 80-24 for a new plant. It stated that a higher recovery

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10 Energy Resources Conservation Board, 1980. Sulphur Recovery Guidelines Gas Processing Operations. ERCB Informational Letter IL 80-24. Calgary, Alberta.

level would require a tail gas clean-up (TGCU) unit and was not justified because there is no evidence of any environmental damage being caused by SO_2 emissions from the plant up until now, added sulphur recovery increases would not result in any measureable environmental benefit, and further increase in sulphur recovery could not be economically justified.

When asked whether it would be Esso's intention to apply for an efficiency of 96.5 per cent even if the Board denied Shell's pipeline application, Esso indicated that, while it had not considered the possibility of Shell's applications being denied, it believed that its current approval limits would remain in effect in that situation.

With respect to the feasibility of 100 per cent sulphur recovery, Esso stated that, although it would be technically possible to approach 100 per cent recovery through the installation of a tail gas clean-up unit, such an investment could not be justified either on the basis of environmental protection nor any reasonable economic criteria. The applicant contended that highly-efficient sulphur recovery processes could decrease SO_2 emissions by up to 4.5 per cent from existing operations, or about 13.8 t/d but that no measurable environmental benefits would accrue from such decreased SO_2 emissions. Additionally, Esso argued that transportation and disposal of the liquid waste products of some of the tail gas clean-up processes would represent an environmental problem and that the frequency of emissions caused by plant start-ups and shutdowns would be increased by the addition of such complex units. Esso stated that the revenues generated from the small incremental amount of sulphur recovery would not off-set even the operating costs let alone the estimated capital cost of between 7.7 and 18.2 million dollars for a tail gas clean-up unit. Esso concluded that a requirement for tail gas clean-up at Quirk Creek would constitute a substantial economic penalty to be borne by the plant owners, gas field producers, and the people of Alberta.

7.2 Interveners' Views

Ms. Hanen and Mr. Russell were of the opinion that the sulphur recovery efficiency of the Quirk Creek plant should be increased whether or not Esso's application was approved. Ms. Hanen argued that the Board had, in past instances, required applicants to meet higher sulphur recovery standards than indicated by IL 80-24, where unusual or extenuating circumstances existed. They further pointed out that IL 80-24 was a guideline and not a regulation, therefore allowing for individual consideration of each case. Ms. Hanen alleged that the adverse effects of SO_2 emissions were already apparent, and therefore, it was not in the public interest to establish irrefutable proof that emissions from the Quirk Creek plant were causing harmful effects. Additionally, she stressed that the Esso application, if approved, would result in a considerable increase in the amount of SO_2 emitted over the life of the plant, and therefore, the probability existed that further environmental

damage would occur. It was her position that older plants with potentially inferior technology and obviously greater susceptibility to mechanical failure, needed as high or higher a standard than new plants because their design was not as modern and their physical condition not as good. Ms. Hanen contended that the production of the highest possible amount of sulphur is itself energy conservation. Witnesses appearing on behalf of Mr. Russell and Ms. Hanen stated that technology was known and in use, to recover essentially 100 per cent of the sulphur present in gas plant emissions and that "best available technology" should be implemented without regard for economics. However, certain of the witnesses believed that the costs could be justified and that the economics were favourable.

Mr. Labuda, who appeared on behalf of Mr. Russell, testified that the cost of such a unit at Quirk Creek would be about 7.0 million dollars (1981) and that these costs could be partially offset by tax incentives for pollution-control equipment and fuel gas savings. Mr. Labuda said that Esso's capital cost estimates for TGCU were probably too high. Although Mr. Labuda stated that economics should not be a consideration, he conceded that, if economics were to be considered, a broad cost-benefit analysis would be preferable to the analysis of incremental project economics. Ms. Hanen agreed, stating that the question of costs was relevant only if "best practical" as opposed to "best available" technology was considered. She argued that the true test of economics is one of a cost-benefit analysis for the total plant, not one of incremental sulphur nor an incremental supply/capacity test.

Ms. Hanen recommended that the Board, regardless of the final disposition of Esso's application, require Esso to install the "best available technology" at the Quirk Creek plant in order to achieve, preferably 99.9 per cent sulphur recovery or as much thereof as is possible, or alternatively, 97.7 per cent as required for new plants with equivalent inlet sulphur capacities, or as a final alternative, 96.5 per cent.

Mr. Russell generally concurred, stating that there is an imperative need for the installation of a full containment facility (ie. a tail gas clean-up unit) at Quirk Creek whether Esso's application to bring in Moose and Whiskey gas is granted or not. Mr. Wolf did not submit evidence with respect to the feasibility of 100 per cent sulphur recovery but did state that no plant should be built that would release any acid gas to the atmosphere.

7.3 Board's Views

As indicated in Section 2, the Board believes that the concept of "best practical technology" is more compatible with its statutory responsibilities of controlling pollution than the concept of "best available technology". The guidelines set forth in IL 80-24, which were adopted after extensive discussions with federal environment officials, are generally consistent with the "best practical technology" standard and

therefore, in the Board's view, should be applied in considering the Quirk Creek plant. IL 80-24 is designed to ensure the maximum practical recovery of sulphur but in considering specific cases, allowance must always be made for any unique or special circumstances.

The Board believes that the following factors are relevant in considering the level of sulphur recovery that should be required of Esso at the Quirk Creek plant:

1. The operator has, with some exceptions, achieved or exceeded a level of 96 per cent for the past few years and the renovations completed in 1981 should improve operations at the plant.

2. In ERCB Report 82-E, the Board found that the proposed production of Moose gas reserves is incompatible with planned recreation development in the Elbow River-Canyon Creek area because of the potential impact on public safety. Consequently, Moose gas will not be delivered to the Quirk Creek plant for processing. While the Board is prepared to approve the processing of the Whiskey gas at the plant, the evidence indicates that it is unlikely that this tie-in could be economically justified. Thus it appears likely that the plant will not process any more or any different gas than is currently allowed for in its approval.

3. While the interveners contended that operations at the Quirk Creek plant had resulted in environmental damage, the evidence does not, in the Board's view, demonstrate damage from SO_2 emissions. That is not to say that there has been no impact from plant operations because every endeavour whether it be agriculture, gas and oil development, or even recreation has an environmental impact. The question that must be addressed is whether or not there has been or will be serious damage. The Board does not see any evidence of serious or unique environmental stress in the vicinity of the Quirk Creek plant area.

Having regard for the foregoing, the Board believes that under current circumstances, the Quirk Creek gas plant approval should continue to provide for a sulphur recovery rate of 95.5 per cent on a quarterly-average basis.

8 THE FEASIBILITY OF INJECTION OF WASTE GASES FROM THE QUIRK CREEK PLANT

8.1 Applicant's Views

With respect to the injection of waste gases for disposal purposes, Esso dismissed the proposal on technical, economic, and environmental grounds. The applicant indicated that it had investigated the feasibility of waste gas injection but had found no proven reservoirs in the area that would be suitable for the volumes of gas anticipated. The Blairmore formations, although unproven with respect to volume available and permeability, were considered to be the only possible receiving formations. Esso stated that a capital expenditure of between 21 and 44 million dollars would be required for a re-injection system capable of generating 3000-9700 kW of compressor power, to compress waste gases to the 17 megapascals necessary to overcome formation pressure and to displace formation fluid. Additionally, the applicant submitted that the fuel requirements of such a scheme could approach 84×10^3 m^3/d of gas and would result in oxides of nitrogen (NO_x) emissions of between 960 and 3000 kilograms per day. Although the use of electrically-driven compressors would eliminate local NO_x emissions, they would result in greater expense and may merely transfer any NO_x emissions to the generating site. Esso also stated that, although major compressor manufacturers had units available for low-pressure H_2S compression, it expected that new corrosion-resistant materials would have to be developed in order to overcome sulphide stress corrosion cracking prevalent at high pressures.

Concerning the injection of waste gases for enhanced oil recovery purposes, Esso stated that the extraction of small quantities of carbon dioxide (CO_2) from acid gas such as are present at Quirk Creek would not likely be economic. Esso submitted that each potential application of CO_2 flooding would have to be considered on its own merits. Respecting the suggestion that CO_2 injection might be used to enhance oil recovery from the Turner Valley Field, it stated that the quantity of CO_2 available from Quirk Creek was not sufficient to make a CO_2 flood viable. The applicant further stated the injection of tail gas (a mixture composed primarily of nitrogen (N_2) and CO_2) for tertiary oil recovery purposes was definitely not practical because of the necessity of treating the tail gas to remove trace quantities of SO_2 and also because of the considerable recompression energy required. Additional expense would eventually be incurred by the oilfield operator to remove or control the NO_x and CO_2 which would be re-produced with the oil. The applicant concluded that it was highly improbable that tail gas injection for enhanced oil recovery would be practical under the circumstances of the present application.

8.2 Interveners' Views

Mr. Jones, on behalf of Ms. Hanen, stated that tail gases contained CO_2 and N_2 were potentially marketable products. He testified that, while CO_2 was a useful flood material for enhanced oil recovery, and N_2 could be utilized as a push gas for miscible-flood schemes, tail gas also could be used as push gas because of its high N_2 content. Mr. Jones further stated that by using tail gas as a push gas to recover additional oil, sulphur and nitrogen oxides would remain in the deep formations, thereby solving the air pollution problem caused by the emission of these gases from sour gas plants. He added that electrically-driven compressors to inject the tail gas would eliminate NO_x emissions that would result from gas-driven compressors. Mr. Jones stated that the additional revenue from enhanced oil recovery would pay for tail gas injection. Additionally, Mr. Jones suggested that because of economies of scale, by consolidating several small plants into one large facility, essentially 100 per cent sulphur recovery (by TGCU) or injection of waste gases would become economically viable. Mr. Jones stated that the risk of corrosion in tail gas injection had been over-emphasized and that the use of epoxy linings for pipelines would provide adequate pipeline protection. However, he did not speak to the question of potential corrosion stress conditions that might prevail within the compressor facilities.

Mr. Labuda testified that, based on the figures provided by Esso, the revenue lost from each of three injection alternatives, that is, acid gas, tail gas, or incinerated tail gas, would be $153 million, $62 million, and $76 million, respectively. Assuming a total 20-year net revenue of $2.5 billion for the overall Quirk Creek plant operation, Mr. Labuda calculated the revenue lost to be 4 to 5 per cent of the total net revenue. He added, however, that the tail gas clean-up processes which could achieve almost 100 per cent sulphur recovery at a much lower cost, would be a much better alternative than the injection scenarios.

Mr. Wolf supported the contention that sour gas could be selectively processed to recover CO_2 and that this CO_2 or tail gas itself could be injected into an oil reservoir for additional oil recovery. Mr. Wolf further stated that an elongated gas reservoir like Quirk Creek, offered an excellent site for re-injection of waste gases to sweep out reservoir gas toward producing wells and such injection would delay the early onset of abandonment pressure. Additionally, Mr. Wolf submitted a preliminary study by a consultant which outlined the porous intervals in seven Quirk Creek wells which he contended would be suitable for re-injection of waste gases.

8.3 Board's Views

The broad question of waste gas injection feasibility is considered by the Board in its general sour gas operations report. With respect to the Quirk Creek plant, the applicant's evidence shows rather clearly that the

possibility of injection of waste gas would be significantly inferior as a means of reducing environmental effects compared to the option of tail gas clean-up.

The Board notes that this conclusion is supported by Mr. Labuda's position that the use of tail gas clean-up processes to recover sulphur would be a much better alternative than the injection of waste gas as a means of avoiding environmental damage. The Board therefore concludes that waste gas injection from the Quirk Creek plant lacks merit and should not be considered further.

The Board has also considered the concept put forward by Mr. Jones and responded to by the applicant of recovering waste gas, either untreated or as a selectively-recovered CO_2 stream, for subsequent enhanced oil recovery injection operations. The evidence shows rather clearly that this kind of program would be very costly to implement and it is doubtful that these costs could be passed along by the plant operator to a potential operator of an enhanced oil recovery scheme. Therefore, although the concept is a technical possibility, the Board is satisfied that it would not be feasible for the Quirk Creek plant and therefore should not be considered further.

9 DECISION

Having regard to all of the evidence, the Board is not prepared to grant Esso the applied-for amendments to Approval 2944. The Board will pursue the matter of the plant's power supply with Esso, and will include the Quirk Creek plant in its proposed study of incinerator stack gases.

DATED at Calgary, Alberta, this 7th day of April, 1982.

V. Millard
Chairman

N. Strom, P.Eng.
Board Member

R. G. Evans, P.Eng.
Acting Board Member

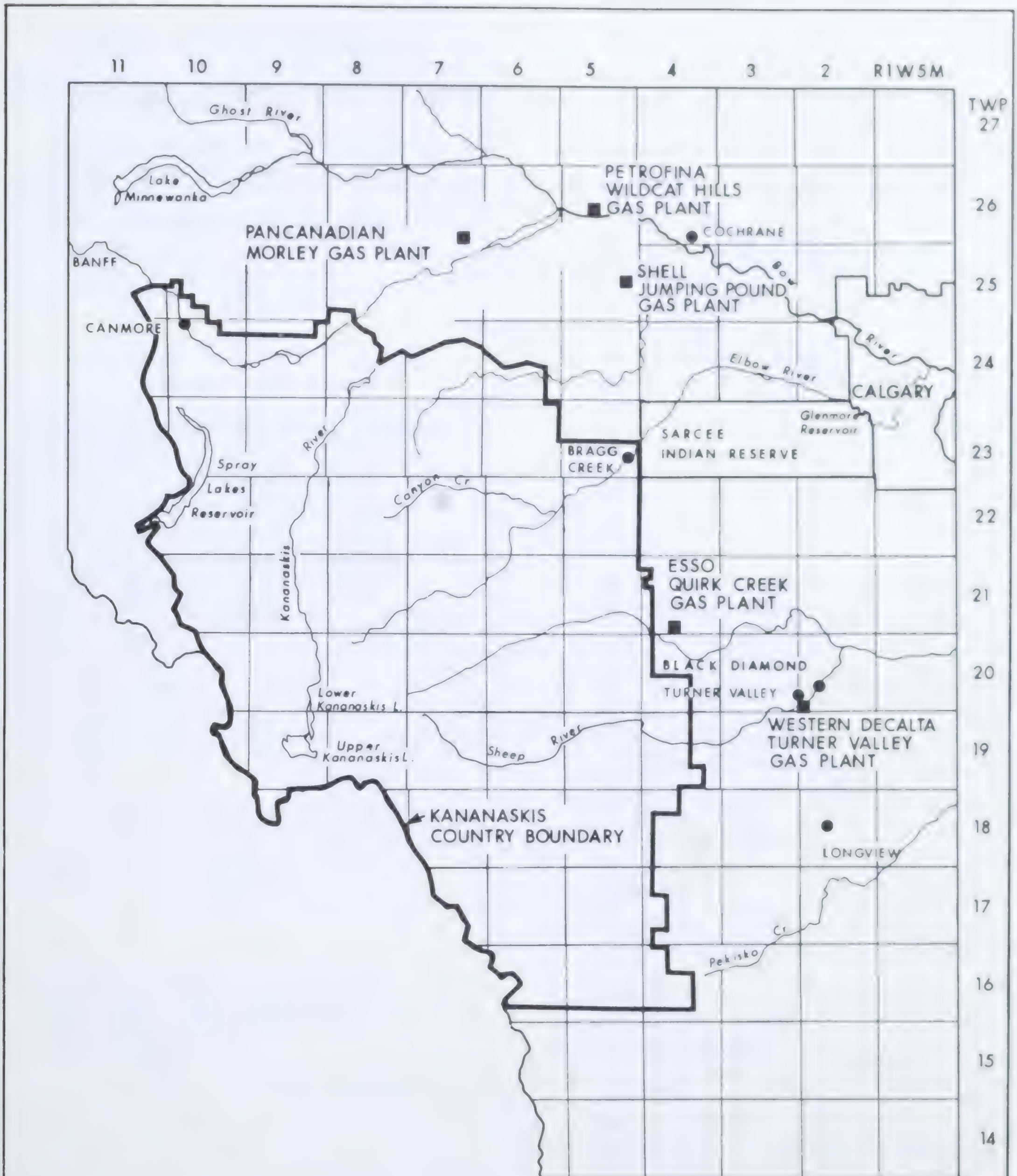


FIGURE TO DECISION 82-12. Esso Quirk Creek and other area gas plants

APPENDIX A TO DECISION 82-12

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Esso Resources Canada Limited (Esso) D. G. Hart, Q.C. R. C. Pittman	N. Walliser Dr. R. G. Auld, P.Eng. B. Toner E. R. Caldwell, P.Eng. J. A. Lore of McKinnon, Allen & Associates (Western) Ltd.
Shell Canada Resources Limited (Shell) D. O. Sabey, Q.C. A.P.G. Walker	
Z. Hanen and Rumsey Ranches (Ms. Hanen) J. D. Rooke	Z. Hanen Dr. R. P. Farran of the Highwood Veterinary Centre Dr. M. S. Kostuch of the Rocky Veterinary Clinic Ltd. E. L. Jones, P.Eng. of Edward Lewis Jones & Associates Consulting Engineers Ltd. Dr. R. F. Klemm of the Alberta Research Council Dr. R. B. Church of the University of Calgary
A. Russell and the Canadian Wildlife Federation (Mr. Russell) P. J. Madden	A. Russell J. Labuda, P.Eng. Dr. G. G. Shaw of the Canadian Wildlife Service Hon. J. Fraser, M.P. Minister of the Environment
R. E. Wolf	R. E. Wolf

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations used in Report)	Witnesses
Alberta Environment staff S. L. Dobko, P.Eng. C. S. Liu, P.Eng. A. Watson of the Attorney General's Department	
Energy Resources Conservation Board staff K. F. Miller H. Knox, P.Eng. Dr. H. Thimm P. Raina, P.Eng. L. Fillion	

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

PEMBINA PIPE LINE LTD.
TARGET AREA CHANGE
QUARTER SECTION DRILLING SPACING UNITS
OSTRACOD OIL PRODUCTION
MEDICINE RIVER FIELD

Decision 82-13
Application No. 810365

1 APPLICATION AND HEARING

Pembina Pipe Line Ltd. applied to amend Order No. SU 1083 to change the target areas for the production of oil from the Ostracod zone in the east half of section 11, township 39, range 3, west of the 5th meridian. The result would be to shift the two Ostracod target areas from their presently prescribed positions in the southwest legal subdivision of each quarter section, to centred areas of the quarter sections, in common with the subsisting target areas for the Pekisko Formation.

The mineral ownership and wells in and surrounding the area of application, and the existing and proposed target areas, are shown in the attached figure.

The application was heard by the Board in Calgary on 11 March 1982, with G. J. DeSorcy, P.Eng., N. Strom, P.Eng., and J. R. Pow, P.Eng., sitting.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Pembina Pipe Line Ltd. (Pembina Pipe) W. E. Martin, P.Eng.	W. E. Martin, P.Eng.
Sabine Canada Ltd. (Sabine) D. P. Andrews, P.Eng.	D. P. Andrews, P.Eng.
Energy Resources Conservation Board staff C.J.C. Page H.J.W. Piët, C.E.T. R. J. Willard, P.Eng.	

BP Canada submitted a letter of intervention supporting the application but did not appear at the hearing.

2 VIEWS OF THE APPLICANT

Pembina Pipe in its application and testimony stated that the centralized position of the wells in Lsd 8-11 and Lsd 16-11 (8-11 and 16-11 wells) would preclude drainage of adjoining leases and would be compatible with the Ostracod target areas in effect in sections 12 and 13.

Pembina Pipe considered it unnecessary and inappropriate to drill two wells when only one dually completed well would suffice. It pointed out that the 8-11 and 16-11 wells were drilled with the Pekisko Formation as the primary objective and that permitting unpenalized production from the Ostracod zone in the same wells would result in maximum economic recovery. The multi-zone completions also eliminate the need for further surface disruption.

3 VIEWS OF SABINE

Sabine opposed the application on the grounds that it would adversely affect the equity of other owners in the pool. It contended that the proposed change in target area would give Pembina Pipe an unfair advantage in unit negotiations and also an opportunity for a second try in a DSU. Sabine maintained that in principle any change of the existing target area regulations in a pool effects the equity in a pool.

Sabine contended that the effects on conservation would not be significant if the wells were allowed to produce without penalty.

Respecting the southeast quarter of section 11, Sabine stated that the application would provide for a second drainage point in the quarter section and therefore the opportunity to produce more oil even though the amount would not be significant.

4 VIEWS OF THE BOARD

The Board believes that the most convenient method of dealing with the application is to consider it for each of the two DSUs involved.

Southeast Quarter of Section 11

The Board notes that the offset DSUs to the east, north, and northeast, are all owned by the applicant. Also the Board notes that the owner of lands to the west, BP Canada, supported the application. The Board concludes there is little prospect for unfair drainage and that the application as it affects this DSU should be granted.

Northeast Quarter of Section 11

The Board observes that the proposed shift in target area in this DSU would allow locating a well closer to Sabine's land than presently prescribed. In this regard the Board concludes that there is potential for unfair drainage of Sabine's lands if the application were granted. Also in the face of the evidence provided, the Board concludes that there may be no more than nominal economic conservation advantages if the application were granted. On balance, the Board concludes that the application as it affects the northeast quarter of section 11 should not be granted.

5 DECISION

The Board grants the application for the SE 1/4 Sec 11-39-3 W5M and Board Order No. SU 1083 will be amended accordingly. The Board denies the application for the NE 1/4 Sec 11-39-3 W5M.

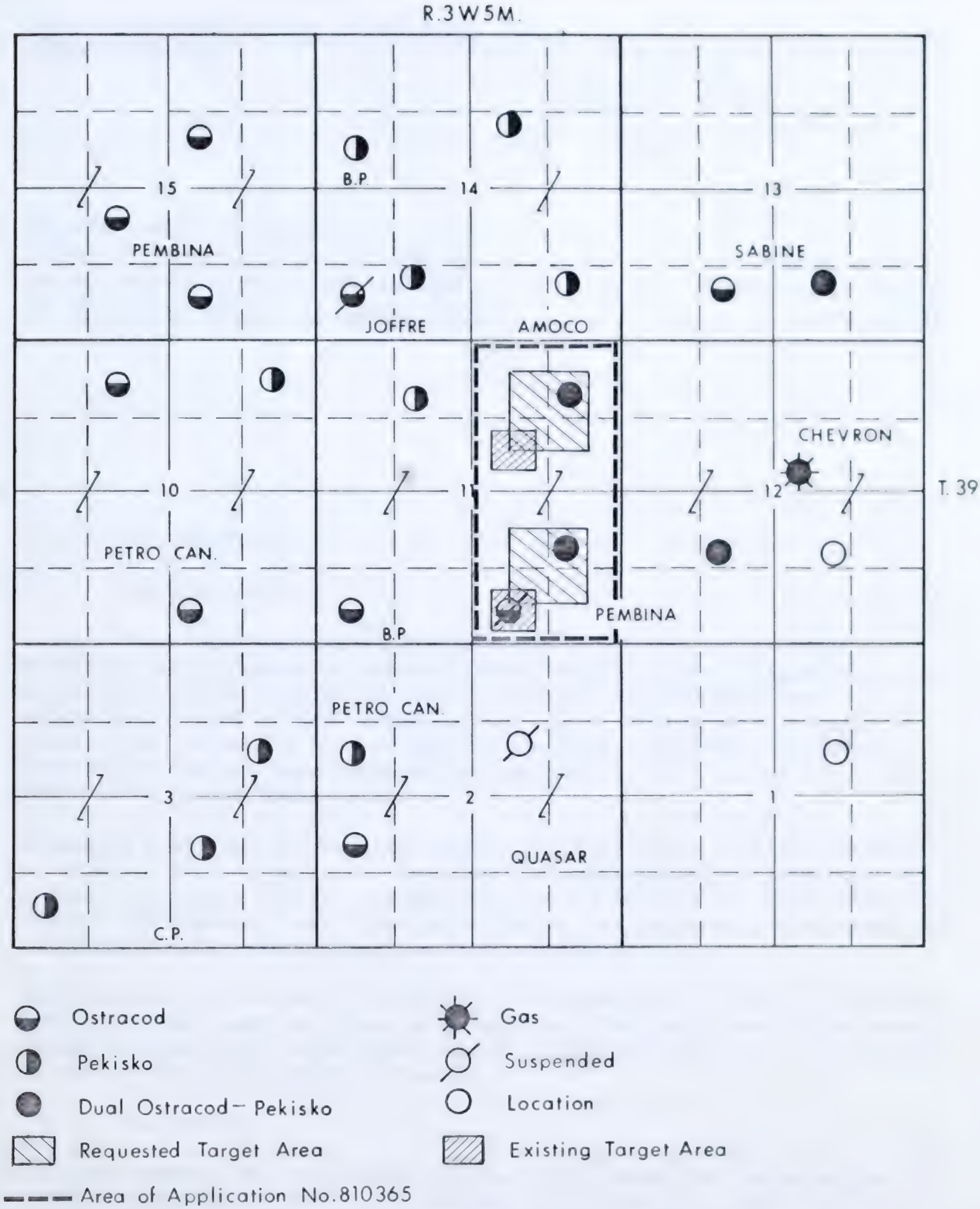
DATED at Calgary, Alberta, on this 7th day of May, 1982.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.

N. Strom, P.Eng.

J. R. Pow, P.Eng.



MINERAL OWNERSHIP AND WELLS IN SE 1/4 39-3W5.

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

ALBERTA POWER LIMITED AND
TRANSALTA UTILITIES CORPORATION'S
240-kV TRANSMISSION LINE FACILITIES
IN THE LOUISE CREEK - SAGITAWAH AREA

Decision 82-14
Applications 810608
and 810733

1 INTRODUCTION

1.1 The Applications

Alberta Power Limited applied, in Application 810608, for a permit to construct and a licence to operate 240-kV double-circuit transmission line AP 938L/939L. The line would run from the proposed Louise Creek substation AP 809S to the service-area boundary on the southern edge of township 64, range 11, west of the 5th meridian (see figure attached). The application was made pursuant to sections 12, 14, 16, and 17 of the Hydro and Electric Energy Act.

TransAlta Utilities Corporation applied, in Application 810733, pursuant to sections 12, 14, and 17 of the same Act for a permit to construct and a licence to operate 240-kV transmission line CP 938L/939L. This line would connect with Alberta Power Limited's line at the service-area boundary and run south to the existing Sagitawah substation CP 77S.

The proposed line would be largely in a forested area in which oil and gas facilities and roads have been developed over the past twenty-five years. Agriculture and other development is not apparent there, and forestry may be the continuing long-term industry.

1.2 The Hearing

The applications were considered by the Energy Resources Conservation Board at a public hearing on 22 February 1982 with C. J. Goodman, P.Eng., E. J. Morin, P.Eng., and E. R. Brushett, P.Eng., sitting.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Alberta Power Limited (Alberta Power) J. Beames	M. H. Whittal, P.Eng. W. J. Beckett, P.Eng. D. G. Smith
TransAlta Utilities Corporation (TransAlta) B. K. O'Ferrall	M. D. Rogers, P.Eng. B. P. Scoble
Esso Resources Limited (Esso) J. E. Lowman	
Federated Pipelines (Federated) L. Larson Conner	
Energy Resources Conservation staff (Board staff) C. J. C. Page, R. L. Schroeder, J. W. Berg, P.Eng., D. Stalport	
R. Dyer of Alberta Environment	

2 DEFINITION OF THE ISSUES

The Board considers the issues to be:

(a) the need for the proposed facilities, and

(b) their location.

3 NEED FOR THE PROPOSED FACILITIES

3.1 Views of Alberta Power

The proposed substation and transmission line are required to meet the load in the Swan Hills area, and to reinforce the capacity of the existing 144-kV and 72-kV lines. In the longer term, the 240-kV facilities would be integrated with transmission extensions to the north and west. Initially only one circuit would be energized.

The Swan Hills load is presently supplied by 25-kV and 72-kV lines, with 144-kV lines being the major transmission lines from the south to loads in this area. The area load is expected to increase rapidly and the existing facilities would soon be overloaded. The substation and line would provide a new and much larger source and avoid the proliferation of lower voltage lines fanning out from the existing 240-kV substations, further south.

The facilities are also needed to meet the present and long-term requirements in northern and western Alberta. At present, if a serious fault occurs on either transmission line 913L between Sundance and Barrhead or Barrhead and Mitsue, the existing system in the northwest would be capable of supplying only 360 MW or 384 MW respectively. Since these are less than the current area load forecasts for 1982, load shedding during peak load periods is a distinct possibility. With the commissioning of the new facilities, the northwest load requirements to about the year 1990 would be met.

The line to Louise Creek would minimize the transmission distance of future 240-kV lines to Sturgeon and Mitsue. In addition the line and substation would significantly increase the load-carrying capacity of all lines in the area. With this reinforcement, the requirement for a 240-kV line to Sturgeon could be delayed.

Alberta Power noted that the double-circuit line would be ideally located to reverse the line's role of importing power into the northwest if future generation projects such as Dunvegan, Fox Creek, or Judy Creek were to proceed. If load in this area, as well as in the Fort McMurray area, continues to grow without off-setting generation, the second circuit will be needed by 1985.

Alberta Power stated, therefore, that the most orderly development in this area will occur if the proposed 240-kV circuits are approved to fulfill the dual purpose of northwest and local electrical power supply.

3.2 Views of TransAlta

Although its application was complimentary to Alberta Power's, TransAlta stated that it preferred to defer questions of need to Alberta Power. TransAlta's application provided for the construction and operation, within its service area, of the proposed 240-kV transmission line.

3.3 Views of the Board

The Board accepts Alberta Power's forecasts concerning load growth in this area. The Board also notes that none of the interveners spoke to the need for the transmission line and substation.

The expected load growth throughout this area will require increased energy support from the south. The existing system in this area is

adequate to meet only present needs and the Board is satisfied that the proposed facilities would support the existing and future requirements until the early 1990s.

The Board accepts that the requirement for a second circuit by 1985 is reasonably well established and therefore believes that the double-circuit line is the most appropriate design. The immediate installation of a second circuit is preferred to the later duplication of the proposed line with a second single-circuit line and associated right of way, or the later addition of a second circuit to existing facilities.

4 THE LOCATION OF THE PROPOSED TRANSMISSION LINE FACILITIES

As shown in the attached figure, Alberta Power's application dealt with two alternative routes, designated Route A and Route C, for the proposed transmission line 938L/939L.

TransAlta's application considered one route, A1 - A28 for the transmission line, except for the portion identified as A28 - A35 and A28 - G5. These two alternatives tie into Alberta Power's Routes A and C respectively as shown in the figure.

4.1 Views of Alberta Power

Alberta Power issued a preliminary referral package in April and May of 1981 and discussed its proposals with various government departments and agencies. It stated that most did not identify major resource or land-use conflicts related to their interests.

Alberta Power noted its meetings with, and discussion of the concerns of the Alberta Forest Service Division (AFS) of Alberta Energy and Natural Resources. In response to questioning, Alberta Power expressed the opinion that the AFS was concerned about the loss of merchantable timber and potentially productive timber lands, and about land-use planning. The applicant agreed that "land-use planning" means the concentration of facilities such as power lines, roadways, and pipelines to avoid other areas.

In a discussion of the definition of "new access", Alberta Power said it understood the term to mean a transmission line right of way that did not parallel an existing right of way. Alberta Power noted, however, that both of its proposed routes were accessible from existing rights of way that cut the proposed routes at right angles or parallelled the routes in their immediate vicinity.

The applicant said its discussions with Simpson Timber, which has timber leases in the area, had determined that the transmission line would not present a barrier to that company's equipment operation and timber harvesting but that Simpson Timber still maintained a preference for Route A.

Alberta Power's portion of Route A, 13.8 kilometres in length, would commence at point A35, and proceed north adjacent to an existing pipeline and 69-kV transmission line to the proposed Louise Creek substation at Site 2. Since the existing 69-kV line would continue to be required for distribution of power in the area, it would not be possible to place the new 240-kV line on the right of way. Alberta Power indicated that approximately 12.8 km of transmission line along Route A would traverse an area considered to have potential for forest production, consisting of 8.5 km of merchantable timber, 1.6 km of burned-over land, and 2.7 km of cleared land. No new access would be required to the transmission line for construction and maintenance. Route A would cross three creeks, however, in Alberta Power's opinion, erosion and impact on fisheries would be minimal. In areas in which an erosion hazard was identified after preliminary survey, trees would be cut by hand, stumps left, and the right of way seeded. Stumps would also be left in some areas to discourage access by all-terrain vehicles. Route A would cross some 12 pipelines and 15 access roads.

Alberta Power indicated that it would remove or trim all trees that could come in contact with the transmission line if they fell toward the line. It therefore requested a variable right of way of 40 - 80 metres to accommodate tree clearing and trimming, depending upon the height of the trees.

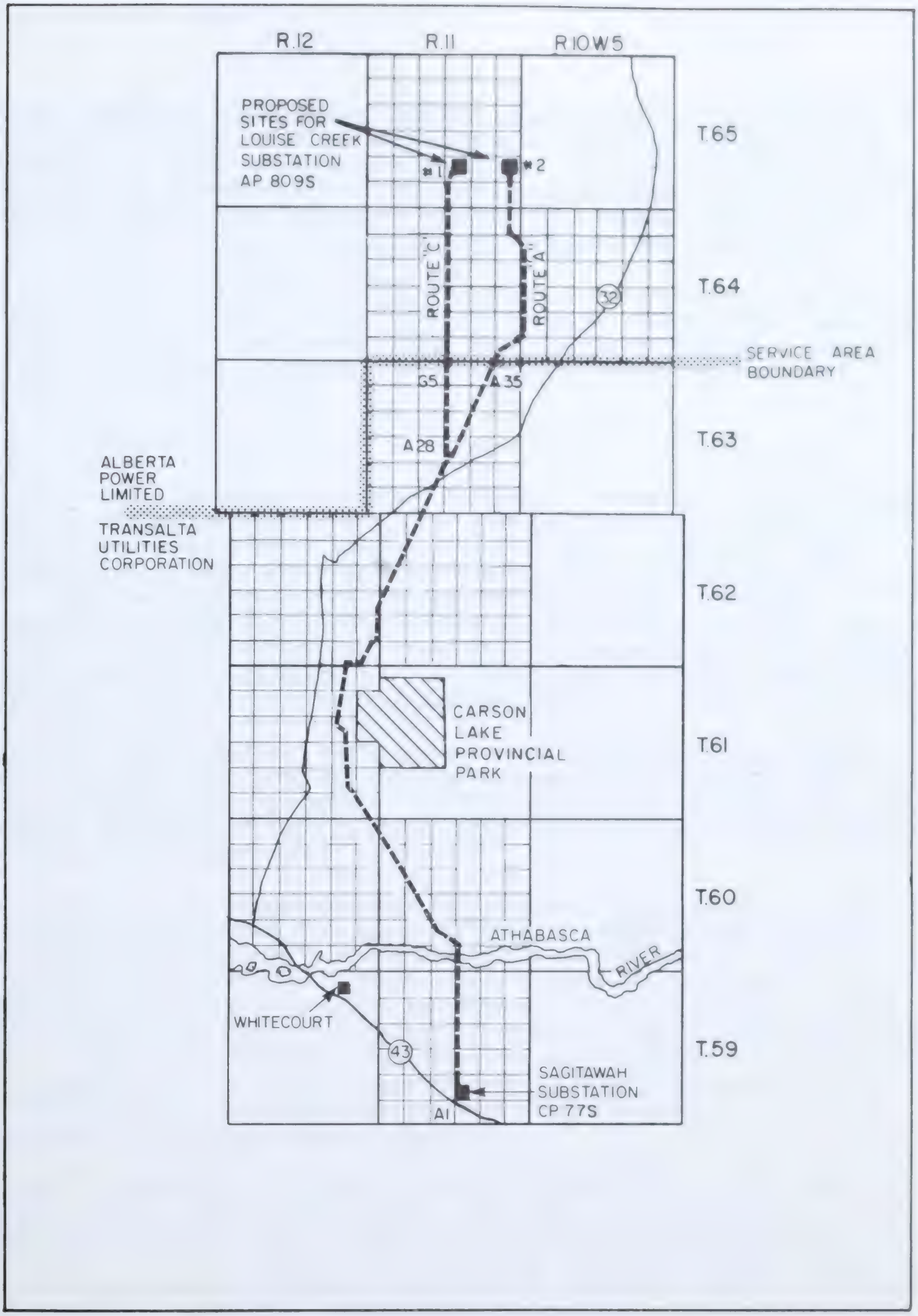
In response to questioning, Alberta Power indicated that the impact on Esso and Federated pipelines, oilfield, and radio communication facilities would be minimal, however, it would meet with Esso and Federated to determine if corrective measures would be required.

The cost of its portion of Route A was estimated by Alberta Power to be approximately $2.4 million. The Louise Creek substation at Site 2, associated with Route A, would be in a wet area and would require a large amount of fill. The estimated cost of the substation at Site 2 was therefore $5.6 million.

Alberta Power's Route C, the applicant's preferred route, would commence at point G5 and proceed 13.1 km north into substation Site 1. This alignment parallels a cleared cut-line and is adjacent and generally east of an existing unimproved road allowance for a majority of the route. Route C does not parallel any oilfield, pipelines, or Alberta Government Telephones (AGT) facilities.

Alberta Power said that some 10.2 km of the proposed line would cross land considered to have potential for forest production, of which 6.3 km is burned out and 3.9 km has merchantable timber. Route C would cross some 8 pipelines and 10 access roads.

Alberta Power indicated that Route C would cross five creeks and that one temporary bridge over a small creek would be needed during construction of the line. In the applicant's opinion erosion and impact on fisheries would be minimal along this route. Since Route C is crossed by several



WHITECOURT – SWAN HILLS AREA

------- PROPOSED ROUTES FOR THE 240 kV TRANSMISSION LINE – SAGITAWAH TO LOUISE CREEK

roads, little new access other than the cleared right of way would be required for construction and maintenance of the line. One section, of perhaps 2 km, might require maintenance work to be done by helicopter but the applicant stated this would be infrequent and would present no major problem. Alberta Power requested approval of a variable right-of-way width of 24.5 - 110 m to accommodate tree trimming and clearing.

The cost of Alberta Power's portion of Route C was estimated to be $1.9 million, some $0.5 million less than for Route A. Alberta Power selected Site 1 as its preferred location for the Louise Creek substation because it has good drainage, requires little fill, and would cost some $0.4 million less than Site 2.

4.2 Views of TransAlta

After crossing the Athabasca River, TransAlta's proposed route north would parallel a pipeline and, from a point west of Carson Lake, would also parallel an existing 69-kV transmission line which would become sub-transmission to serve the area. There would be a minimum separation of 30 m from the pipeline and 24.5 m from the 69-kV line. TransAlta considered the possibility of treed buffers but thought contiguous cleared rights of way were preferable. TransAlta would require 24.5 m of cleared right of way and would selectively cut beyond that to remove trees that might otherwise fall onto the transmission line.

TransAlta said it had met and discussed its proposed route near Carson Lake Provincial Park with AFS and Alberta Parks and Recreation; and concerns with respect to creek crossings, brushing and merchantable timber would be resolved. TransAlta stated that there would be no visual impact on the park or campground.

In response to the suggestion that the proposed transmission line might interfere with existing pipeline facilities, TransAlta stated it would meet with the operators, Esso and Federated, to determine if corrective measures would be required. The proposed transmission line would cross only one fenced private property and only one residence would be located within 80 m of the line. TransAlta indicated that the proposed line would have minimal impact on recreation, wildlife, and fisheries. TransAlta did not suggest any alternative routes from A1 - A28 and contended that its recommended route offered major advantages over all other routes it had considered in its preliminary evaluations.

TransAlta submitted two sub-alternatives to connect with Alberta Power's Routes A and C, shown in the figure. Route A28 - A35 would parallel a right of way cleared for an existing pipeline and transmission line. Route A28 - G5 would cross pipeline clearings and access roads throughout. It would parallel an existing narrow cutline, interfere less with existing and future oil facilities, and would be shorter and require less brushing than Route A28 - A35. TransAlta indicated a preference for Route A28 - G5 provided that Route C of Alberta Power's application were approved. The total cost of the TransAlta section of transmission line was estimated to

be \$8.2 million to point A35. The westerly route would cost an estimated \$0.15 million less than the easterly route.

4.3 Views of the Interveners

Esso and Federated were concerned that the proposed line would interfere with existing facilities along both TransAlta and Alberta Power sections of line. They requested that both utilities meet with them to determine if any corrective measures are required.

Esso questioned the proximity of parts of Route C to its oil and gas well sites, and also to coal reserves in the area, but did not appear to favour either route. Federated questioned possible effects on its existing facilities along proposed Route A and favoured Route C, since it was away from these facilities.

4.4 Views of the Board

The Board assessed the two alternative routes on the basis of a number of matters raised in the applications or brought out at the hearing. Most of the evidence applied to Alberta Power's alternative routes.

Neither alternative would involve cultivated land or private property, but both proposed rights of way have potential for timber production. Both alternatives are located in areas of oil and gas industry development, but Route A parallels more existing development and an all-weather road. Specifically, Route C would cross some 8 pipelines and 10 access roads, while Route A would cross some 12 and 15 respectively. Also, Route A could be reached from a parallel main road, whereas Route C could be reached at various road-crossing points and the right of way itself used as a construction trail.

Other criteria considered included: forest resource considerations such as existing merchantable timber, potential forest production, and tree clearing; impact on fisheries and potential for increased erosion; the impact on existing linear facilities; access to the transmission line for construction and maintenance, and public access. In addition, the matter of parallelling existing linear development as opposed to new linear right of way on less-developed land was considered.

With respect to the forest resource consideration, the Board notes from information supplied by the applicant that Route A removes more area from potential timber production than Route C. The Board accepts that the existing 69-kV line must remain, and therefore on Route A a greater amount of tree clearing is required to prepare the route for installation of the proposed line compared to Route C. The right of way on Route A would traverse 2.0 km less burned-over land and cleared land than Route C, and therefore would require a greater amount of tree clearing. The Board concludes that Route C would have less current and future impact on the forestry resources than Route A.

The Board assessed the potential impact of the two proposed routes on fisheries and on erosion of stream banks. Route C crosses a greater number of streams than Route A and would require a temporary bridge over one of the smaller crossings. Since mitigative measures can and must be taken to lessen the effects of erosion, and construction activities could be restricted to a time of year not as critical to the fish habitat, the Board believes that Route C would have only slightly more impact than Route A.

The Board notes that Route A parallels existing pipelines for most of the route and would require six or more deflections solely to avoid physical conflict with existing pipelines. Mitigative measures might be required on Route A to minimize electrical interference with existing pipeline facilities. The Board agrees with the interveners that a meeting of the applicants and industry should be arranged in order to determine what mitigative measures may be required and to arrive at a mutually agreeable solution, but does not believe that impacts are so serious as to rule out Route A. The Board believes that Route C would have minimal impact in this respect because it does not parallel existing pipeline facilities.

Both proposed routes provide adequate access for transmission line construction as normally carried out in such areas, although Route A may have some slight advantage depending upon weather conditions at the time of construction. Routine line patrols would be from the air and on the ground maintenance would be infrequent. However, the northern end of Route C could be difficult to reach if it ever needed emergency repairs. Public access exists now in the area of both routes, but parts of Route C could be more open to the public along a cleared right of way. The Board expects the applicant to discuss aspects of access limitation with Alberta Energy and Natural Resources.

Land-use planning related to location of linear developments was raised but not pursued to any great depth. However, the Board recognizes that such public-interest concerns may exist. The information available for Routes A and C indicates that much of the present development is related to the oil and gas industry and this may have a limited life related to resource depletion. Part of the area is underlain by coal resources, and the forest industry is active in the area. A large area has recently burned but should eventually regrow, and Route A is near a well-developed road while Route C is adjacent to an undeveloped road allowance. The Board accepts that a land-use planning argument could be made for continuing linear development where it already exists and accepts that in this case Route A may be the more favourable.

The Board believes that Route A is a more satisfactory choice with respect to access for construction or maintenance, public access, and possible future land-use considerations. Route C is preferable from the standpoint of forestry and the impact on existing pipelines. Based on these considerations, neither proposed route is distinctly preferable to the other.

The Board has also considered the costs to the utilities and their customers. The proposed substation at Site 2, located at the end of Route A, would require a large amount of fill and the Board accepts the estimated cost of approximately $0.4 million more than a substation at Site 1. The cost of constructing the line on Route A, including the extra brushing and numerous deflections to avoid pipeline facilities, is estimated to cost about $0.5 million more than a line on Alberta Power's Route C. Choosing Route A would also add $0.15 million more on TransAlta's portion of the route. Therefore, on the basis of an extra cost of about $1 million the Board concludes that Route C and the substation Site 1 at the northern end of Route C is preferable to Route A and Site 2.

The Board notes Alberta Power's application for a variable-width right of way considerably wider in some places than 24.5 m. However, on the basis of the information presented, the Board does not believe it should approve rights of way wider than 24.5 m for the routes proposed. It is accepted that tall trees must be prevented from falling against any line that is built, and that clearing may be necessary in the areas beyond the 24.5 m width, as outlined by the applicant. In such cases it will be necessary for Alberta Power to negotiate with AFS for the additional clearing required. It is also possible that in areas now burnt but regrowing, it may be necessary to clear beyond the 24.5 m right of way requested by Alberta Power.

The Board notes that TransAlta considered several routes and accepts that it chose to present the one which TransAlta believed to have minimal impact on recreation, wildlife, and fisheries. The proposed route does not appear to cause major impacts on Carson Lake Provincial Park. Minor impacts can and should be resolved. There may be some problems with electrical interference with Esso and Federated facilities, but the Board expects that a mutually agreeable solution can be worked out. On this basis, the Board agrees with TransAlta's proposed route from A1 to A28. The Board agrees with TransAlta that the route from A28 to G5 has an advantage over the route to A35 provided Alberta Power's Route C is also the best choice.

5 FINDINGS

The Board has found it necessary to weigh a number of qualitative factors along with the quantitative factors available, and finds that:

1 There is an established need for the existing lower voltage lines and for a 240-kV transmission line as proposed, and that future need is sufficiently certain to make construction of a double-circuit line prudent.

2 The accepted estimate of $1.0 million in extra costs for Route A, more than offsets the approximate balance of other factors. Therefore, the Board accepts Route C and substation Site 1 as the preferred choice.

3 TransAlta's proposed route from points A1 to A28 to the G5 connection with Alberta Power's Route C is the preferred choice.

4 The appropriate right of way width is 24.5 m recognizing that tall trees beyond the right of way should be removed if they could fall and touch the transmission line.

6 DECISION

The Board approves Application 810608 of Alberta Power Limited along Route C, and Application 810733 of TransAlta Utilities Corporation through points A1, A28 to G5 as shown in the figure. Subject to the approval of the Ministers of the Environment and of Energy and Natural Resources insofar as the application affects matters of the environment, the Board will issue the permits and licences in due course.

ISSUED at Calgary, Alberta, on 27 May 1982

ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

E. J. Morin

E. J. Morin, P.Eng.
Acting Board Member

E. R. Brushett

E. R. Brushett, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

GAS PROCESSING PLANTS
CANTERRA ENERGY LTD.
GULF CANADA RESOURCES INC.

Decision 82-15
Application Nos. 810650 & 810849

Canterra Energy Ltd. applied, pursuant to section 38 of The Oil and Gas Conservation Act[1] (the Act), to amend Approval No. 2820 without increase in design capacity but including additional fields and increase in sulphur recovery efficiency to 98.4 per cent for its Ram River gas processing plant located in the south half of section 2, township 37, range 10, west of the 5th meridian.

Gulf Canada Resources Inc. applied, pursuant to section 38 of the Act, to amend Approval No. 3351 to include additional fields and increase sulphur recovery efficiency to 98.4 per cent for its Strachan gas processing plant located in section 35, township 37, range 9, west of the 5th meridian. Gulf requested that the Chedderville Field be added immediately at the current sulphur recovery efficiency of 97 per cent and that the other fields not be added until the plant's sulphur recovery efficiency was increased to 98.4 per cent.

The applications were considered by the Board at a public hearing at Red Deer, on 26 and 27 April 1982, and in Rocky Mountain House, on 3 May to 6 May 1982, inclusive, with V. Millard, N. Strom, P.Eng. and R. Evans, P.Eng. sitting.

The Board has completed its assessment of the evidence adduced at the hearing and has reached its decision respecting the two applications. The Board is satisfied that it would be in the public interest to process the additional gas reserves at the Canterra and Gulf plants and that the applied-for sulphur recovery rate for each plant is appropriate having regard for all relevant factors.

1 Now section 26 of the Oil and Gas Conservation Act.

Accordingly, the Board, subject to the approval of the Minister of the Environment with respect to environmental matters, approves the amendments requested by Canterra Energy Ltd. and Gulf Canada Resources Inc. The reasons for the Board's decision will be presented in a Decision Report to be released later.

ISSUED at Calgary, Alberta this 12th day of May 1982.

V. Millard
Chairman

N. Strom
Board Member

R. Evans
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

CANTERRA ENERGY LTD.
RAM RIVER GAS PROCESSING PLANT
AND
GULF CANADA RESOURCES INC.
STRACHAN GAS PROCESSING PLANT

Addendum to Decision 82-15
Applications 810650 and 810849

TABLE OF CONTENTS

1 INTER-RELATIONSHIP OF APPLICATIONS

Aquitaine (now Canterra) and Gulf applied in mid-1981 to install a series of pipelines for the purpose of gathering sour gas from several new gas pools at South Hanlan-Brown Creek (centred around Township 45, Range 16, W5M) and transporting it southeastward to dehydration/compression facilities at Stolberg (Township 41, Range 14, W5M) and from there through existing pipelines to the Canterra Ram River and Gulf Strachan plants (centred around Township 37, Range 10, W5M).

The combination of these installations, along with certain plant modifications and gas exchange arrangements between Canterra and Gulf, was aimed at efficient utilization of sour gas processing capacity available at Ram River and Strachan plants, thus rendering a number of economic, energy conservation, and environmental advantages. Decision 82-2[1] approving the pipeline applications was issued 21 May 1982. This followed issuance on 12 May 1982 of Decision 82-15, a brief statement of decision approving the related plant applications. The following is a full report on the basis for Decision 82-15.

2 THE APPLICATIONS

2.1 The Canterra Application 810650

Canterra applied to process additional sour-gas reserves from the Blackstone Field and Area and the Jupiter and Brazeau River areas[2] at its Ram River plant. The applicant stated that it expected that future reserves discovered in the outlying areas on both sides of the presently proposed gathering system (Figure 1) would also be processed at the Ram River plant. Thus, the plant would continue to be the central processing unit for sour gas fields extending along the foothills trend from Ricinus to South Hanlan-Brown Creek.

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1 Energy Resources Conservation Board, 1982. Aquitaine Company of Canada Ltd., Gulf Canada Resources Inc., NOVA, AN ALBERTA CORPORATION, Permit to Construct Pipelines in the Stolberg-Ricinus Areas. ERCB Decision 82-2. Calgary, Alberta.

2 Also referred to as the South Hanlan-Brown Creek areas in previous pipeline applications.

If the application were approved, the plant throughput would not exceed the presently-approved capacity of 17 749 thousand cubic metres (10^3 m^3) per day of raw gas feedstock containing not more than 3437 x 10^3 m^3 of hydrogen sulphide (H_2S) (4660 tonnes sulphur). In fact, production from fields presently supplying the plant is declining and large and increasing unused capacity will occur. Projected maximum production rates from the new reserves would be 4160 x 10^3 m^3 per day of raw gas containing 501 x 10^3 m^3 of H_2S and this would partially replace expected declines from the Ricinus West and Strachan fields totalling 4430 x 10^3 m^3 per day of raw gas containing 1360 x 10^3 m^3 of H_2S.

At the plant's currently approved sulphur recovery efficiency of 98.0 per cent, the applicant's proposal would result in a 23.4 per cent increase in the cumulative amount of sulphur dioxide (SO_2) emitted from the plant over its projected life (to 2005). Subsequently, Canterra amended its application to provide for increasing its annual sulphur recovery efficiency level to a minimum of 98.4 per cent and a quarterly recovery of not less than 98.0 per cent. The cumulative total SO_2 emissions, for the currently-approved reserves at the current recovery efficiency of 98.0 per cent, was estimated to be 522 445 tonnes for the projected plant life. Total projected emissions for the same period, based on approval of the application at 98.4 per cent recovery, was 515 844 tonnes of SO_2. The applicant contended that its amended application would therefore result in a net decrease in SO_2 emissions of approximately 6600 tonnes.

2.2 The Gulf Application 810849

Gulf applied to process additional sour-gas reserves from the Blackstone, Brown Creek, Big Horn, Cordd, and Voyager areas[3], and the Ricinus, Stolberg, and Chedderville fields, to restore and maintain throughput at its Strachan gas-processing plant. Gulf stated that the applied-for reserves, plus potential reserves south of the Strachan and Ram River plants would likely keep both plants loaded for many years. The applicant also stated that the possibility for further gas developments in these areas was favourable and that it was confident that some future reserves would be processed at its Strachan plant.

If the application were approved, the plant throughput would not exceed the currently-approved capacity of 7748 x 10^3 m^3 per day of raw gas feedstock containing not more than 716 x 10^3 m^3 of H_2S (971 tonnes sulphur equivalent). Gulf stated that the Strachan gas plant is currently operating at about one-third of capacity; approval of the applied-for reserves would bring plant operations up to

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3 Also referred to as the South Hanlan-Brown Creek areas in previous pipeline applications.

about two-thirds of design capacity. The applicant submitted that approval to process these additional gas reserves was necessary to sustain plant operations and to ensure optimum depletion of the Strachan reservoir from which production is declining rapidly.

Gulf applied for permission to process the additional reserves at the currently-approved sulphur recovery efficiency level of 97.0 per cent. Gulf subsequently amended its application such that the processing of Chedderville gas would begin by late 1982 without modifications to the sulphur recovery plant. However, the remaining applied-for reserves would not be brought on stream until a tail gas clean-up unit (TGCU) capable of a 98.4 per cent annual sulphur recovery efficiency was installed. Gulf estimated that this could not be accomplished until at least mid-1983 and since it was still in the preliminary assessment stage, it could not specify what type of TGCU it would install. Gulf concluded that the application, if approved including a TGCU, would result in a net decrease in SO_2 emissions of approximately 50 500 tonnes compared to that expected under the existing approval.

3 THE HEARING

The Board considered the applications at a public hearing in Red Deer, Alberta on 26 and 27 April 1982 and in Rocky Mountain House on 3 through 6 May 1982 with V. Millard, N. Strom, P.Eng., and R. G. Evans, P.Eng., Acting Board Member, sitting.

Table 1 is a list of those who appeared at the hearing.

4 PRELIMINARY MATTERS

At the commencement of the hearing, certain matters were raised by counsel for the participants concerning the filing of additional information and certain procedural questions.

Mr. Saville, referring to a report on the technical feasibility and costs of improved tail gas clean-up retrofit for the Canterra Ram River plant prepared by Fluor, noted that the report was only recently completed and had not been filed as part of the application. Noting that the report had not been required to complete application documentation, Mr. Saville proposed not to file it at this proceeding.

TABLE 1

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Canterra Energy Ltd. (Canterra) F. M. Saville R. A. Neufeld	J. E. Martin, P.Eng. D. A. McCoy, P.Ag. A. R. Laundry, P.Eng. all of Canterra Energy Ltd. D. M. Leahey of Western Research and Development Ltd. R. Jackson of Core Laboratories - Canada Ltd. J. Hilldred, P.Eng. of Fluor Canada Ltd. R. H. Leitch, P.Ag. of Hardy Associates (1978) Ltd. B. F. Bietz of MacLaren Plansearch Services Ltd. R. A. Crowther of IEC International Environmental Consultants Ltd. P. Addison of Northern Forest Research Centre of The Canadian Forest Service J. E. Marsh
Gulf Canada Resources Inc. (Gulf) J. D. Anderson J. Nozick	L. T. L. Callow M. Wright, P.Ag. D. J. Lovitt, P.Eng. R. B. Horne M. A. Sharpe all of Gulf Canada Resources Inc. W. Murray of Promet Environmental Group Ltd.

THOSE WHO APPEARED AT THE HEARING cont'd

Principals and Representatives (Abbreviations used in Report)	Witnesses
Rocky Veterinary Clinic Ltd. (M. Kostuch) R. D. Schachter H. J. Sniderman	M. Kostuch M. H. Chaudhry of Lakeland College
Federation of Alberta Naturalists and The Alberta Fish and Game Association (FAN, and Fish and Game) L. F. Duncan	E. Kure of The Alberta Fish and Game Association
Public Advisory Committee to the Environment Council of Alberta (PAC) R. Whistance-Smith	R. Whistance-Smith
Red Deer Fish and Game Association H. Lembicz	H. Lembicz
Government of Alberta A. R. Watson C. S. Liu S. Penttinen	
Energy Resources Conservation Board staff M. J. Bruni D. G. Pearson, P.Eng. E. P. Moeller, C.E.T. L. S. Fillion H. F. Thimm	

Mr. Schachter, representing M. Kostuch, made reference to the following factors on which he requested a Board ruling:

- Referring to ERCB Report 82-D[4], a general report on sour-gas processing in Alberta released a week before the hearing, and the potential relationship of that report to the current proceedings, Mr. Schachter requested that the Board consider holding a general inquiry on the matters referred to in Report 82-D but with widespread publicization and a better opportunity for full public participation than that which occurred during the Quirk Creek and Jumping Pound proceedings[5]. He proposed that such a general inquiry of the environmental facets of the sour-gas industry should be completed before the Board should undertake disposition of the Canterra and Gulf applications.

- Environmental studies dating back to 1972, and referred to by Canterra as the basis of its view that negligible environmental impacts have occurred, were requested to be filed in order that the environmental implications of the Canterra applications would be fully examined.

- Detailed tabulations of product streams including sulphur, plant by-products, fuel gas consumption, product quality if a TGCU is installed, and overall revenue streams from all sources at the plant (both actual 1981 and projected), overall plant economics, information to allow assessment of the effect of recent royalty revisions on plant economics, tax deductions for pollution control equipment, allocations of plant overhead, etc. In summary the information would be aimed at reviewing overall economics of operations, with and without potentially improved TGCU facilities.

- Detailed cost information relating to each of the TGCU methods investigated, in order to allow detailed economic assessment of the Fluor report.

- Referring to Section 5(1) of Report 82-D, Mr. Schachter cited the Board's conclusion regarding best practical technology, "The

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4 Energy Resources Conservation Board, 1982. Sour Gas Processing in Alberta. ERCB Report 82-D. Calgary, Alberta.

5 Refer to ERCB Decision 82-3. Shell Canada Resources Limited Jumping Pound Gas Processing Plant and ERCB Decision 82-12 Esso Resources Canada Limited Quirk Creek Gas Processing Plant.

technology which achieves the best results in controlling sulphur dioxide emissions to a level which is reasonable in terms of environmental impact, economic and conservation matters." He maintained that overall economics and also the detailed economic data on TGCU were required for the Board to come to a sound conclusion on whether in the particular instance of the Canterra plant "best practical technology" is equivalent to "best available technology."

L. Duncan, representing FAN and Fish and Game and also speaking for the Alberta Environmental Law Association, requested that the Board proceed with a general inquiry on the sour-gas industry as proposed by Mr. Schachter. Respecting the Canterra and Gulf applications, Ms. Duncan made three optional proposals:

a. adjourn the hearing until the proposed general inquiry was completed,

b. hear the Gulf and Canterra applications but deferring a decision thereon so as to have regard for any overriding policy considerations that might arise from the general inquiry, or

c. If neither a. nor b. were acceptable, that the Canterra and Gulf applications be heard but recommendations thereon be subject to the condition that licence standards for sulphur dioxide emissions be established for a maximum period of three years, at which time a new hearing would be called specifically for the purpose of establishing new standards based on the policies and evidence then available.

Board Rulings on Preliminary Matters

The Board deliberated on each of the information requests and procedural matters put before it and concluded as follows:

- Request for General Inquiry. The Board advised participants that it would be altogether inappropriate for the Board to initiate an inquiry into its own report (Report 82-D). However, in view of the several environmental aspects raised in the report, the Board had already invited comments by the Environment Council of Alberta and the Board would be open to considering a properly constituted and properly supported proposal for an inquiry. The Board pointed out that the current proceedings were not the proper forum for such consideration and set aside the request.

- Scope of Current Proceedings. The Board ruled that very broad environmental matters such as those referred to in Report 82-D would not be considered at the current proceedings - even though they had been in the Quirk Creek and Jumping Pound hearings - and that the participants were expected to restrict their evidence and cross-examination to matters that related to the specific applications by Canterra and Gulf. This would allow interveners to submit technical, economic, and environmental evidence pertaining to the plants but not get into broad regional or philosophical environmental issues such as those referred to in Report 82-D.

- Fluor Report. The Board ruled that the Fluor Report was to be filed as evidence pertaining to the Canterra application. However, concerning the request by Mr. Schachter for additional detailed costs breakdown on the TGCU processes studied, the Board ruled that evidence in the report was of sufficient detail for the purpose of considering the current application, having in mind the competitive nature of such details and that there would be a witness to speak to the evidence.

- Request for Additional Environmental Information. The Board ruled that environmental impact is one of the factors that should be considered in determining the extent to which emissions from the Ram River plant should be controlled and requested that Canterra provide a suitable set of environmental monitoring information which it had compiled in regard to impacts on vegetation, soil, and aquatic environment.

- Economic Details on Costs and Revenues. The question of detailed cash flow data hinged on whether or not overall economics versus incremental economics would be decisive in assessing the acceptability of the Canterra application. The Board observed that tail gas clean-up would not likely be shown to be economic regardless of the manner of detailed manipulation of data, and also that in accordance with IL 80-24[6] - the joint policy statement of Alberta Environment and the Board - overall economics should not be applied in a rigorous fashion but may be required to generally assist in reaching a conclusion on certain cases. Having regard for the foregoing, the Board concluded that:

    a. It was not prepared to ask Canterra to supply the extensive package of economic information requested by Mr. Schachter.

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6 Energy Resources Conservation Board, 1980. Sulphur Recovery Guidelines Gas Processing Operations. ERCB Informational Letter IL 80-24. Calgary, Alberta.

b. Because it is a competitively sensitive matter, is laden with much personal judgement, and can be readily developed by an experienced economist, the Board would not require Canterra to supply forecasts of product prices.

c. In order to allow reasonable investigation of the effects of the proposed changes, Canterra would be required to supply a projection of incremental products streams occurring at the plant as reflected by pre- and post-application forecasts.

Having regard for the requirements for additional information, and as agreed to by all participants, the hearing was adjourned and was resumed on 3 May 1982 in Rocky Mountain House.

5 THE POSITION OF THE INTERVENERS

The Board heard interventions from M. Kostuch for the Rocky Veterinary Clinic Ltd., the Alberta Fish and Game Association and the Federation of Alberta Naturalists, the Red Deer Fish and Game Association, and the Public Advisory Committee to the Environment Council of Alberta. All dealt essentially with environmental matters, as did the examination of the Government of Alberta.

A common position of all interveners that submitted direct evidence was the contention that the long-term impact of low-concentration SO_2 emissions on soil, animal health, vegetation, and water were unknown but conceivably could be serious having regard for cumulative effects. Additionally, it was felt that environmental studies performed to date were of too short a duration to properly address this question.

M. Kostuch did not, in principle, oppose the application, but did express concern regarding the impact of SO_2 emissions on her land, primarily with respect to possible soil acidification and livestock diseases related to dietary selenium deficiencies. In support of these contentions, evidence concerning potential SO_2 deposition rates on soil was presented by an expert witness.

Although M. Kostuch did not oppose the sulphur recovery level of 98.4 per cent as applied for by Canterra, she expressed the view that 99 per cent recovery would be preferable because the potential long-term impacts would thereby be lessened. She suggested that the provisions of IL 80-24 would tend to classify the application to bring in substantial additional raw gas to the Ram River plant as a suitable premise for requiring 99 per cent sulphur recovery. If the 98.4 per cent recovery level proposed by the applicant were approved by the Board, M. Kostuch argued that the following conditions should be attached to the approval:

a. That an increase in sulphur recovery of 0.1 to 0.3 per cent higher than that applied be required.

b. That a gas/gas heat exchange system be installed.

c. That technical reports on the performance of new catalysts currently under development, be filed with the Board and be made available to the interveners, and that the applicant utilize new catalysts that demonstrate improved performance.

d. That within two years of the approval, the applicant provide a report to the Board on the availability of new technology for increased sulphur recovery, and that the report be made available to the interveners.

In addition, M. Kostuch asked the Board to voice support for her proposal which recommended the appointment of a environmental committee (also referred to as a "tripartite" committee), consisting of representatives of Canterra and Gulf, the public, and the government for the purpose of guiding environmental research and monitoring.

FAN and Fish and Game expressed concerns about the long-term viability of the lake trout resource in Swan Lake in the presence of airborne pollutants, and were sceptical about the scientific foundations underlying the mathematical modelling of SO_2 depositions over an extended range of distances. These interveners also did not oppose the application, but requested conditions in the approval as follows:

a. That the standard of 98.4 per cent be an immediate requirement to apply to the processing of existing reserves.

b. That this standard remain in effect for a maximum period of two years with subsequent review on the basis of technological advances and results of environmental studies in progress at the present time.

c. That Canterra be required to report to the Board, at the earliest possible date, on the success and efficiency of proposed modifications, and that these reports be made available to the public.

FAN and Fish and Game also supported M. Kostuch's call for an environmental committee.

The essential positions of the interveners towards the Gulf application, and the underlying environmental arguments, were the same as those stated in the Canterra application. The application was not opposed in principle, but only conditional approval was recommended.

M. Kostuch stated that in her opinion the Strachan plant would be in compliance with IL 80-24 with the proposed modifications, and asked that no additional reserves, except those from the Chedderville Field, be processed until those modifications were complete. She further requested the submission of a report two years from now concerning sulphur recovery technology, with the same conditions of public accessibility to the information contained therein.

FAN and Fish and Game took a similar position and asked for approval subject to the same conditions as outlined in their interventions to the Canterra application, with the exception that the 98.4 per cent sulphur recovery requirement would be adopted when the additional reserves started producing.

6 THE ISSUES

The Board considers the main issues respecting the applications to be:

- suitability of processing the new sour-gas reserves from the South Hanlan-Brown Creek area and Chedderville Field at the Ram River and Strachan plants,
- technical, and conservation matters, and
- environmental matters.

7 SUITABILITY OF PROCESSING NEW SOUR-GAS RESERVES AT THE CANTERRA RAM RIVER PLANT

7.1 Views of Canterra

In Canterra's view, processing of the new sour-gas reserves at its existing Ram River plant was clearly preferable to alternative plants or to constructing new facilities whether assessed on purely economic, conservation, or environmental grounds. Canterra submitted that its proposal would cost approximately \$30 million as opposed to \$120 million for the expansion of Gulf's Robb-Hanlan plant or \$200 million for the construction of a new plant in the area of the reserves. Furthermore, the applicant stated that the processing of the additional reserves at the Ram River plant would result in the cost of processing reserves already connected to the plant to be lower because of greater overall utilization of plant capacity.

Canterra also submitted that processing of the additional reserves at its existing plant would result in a greater recovery of sulphur than at a new plant. It pointed out that the average inlet sulphur production rate from the additional raw gas reserves would be approximately 600 tonnes per day (t/d), and that a new plant with a 600-t/d sulphur inlet capacity would be required by IL 80-24 to achieve a quarterly sulphur recovery efficiency of 97.8 per cent - slightly below the 98.0 per cent now specified for the Ram River plant. Further, the applicant stated that less natural gas would be consumed as incinerator fuel when processing a given volume of raw sour gas at a larger plant rather than at two smaller ones, and overall conservation of energy would be greater.

Canterra also contended that by bringing sour gas from fields in the foothills area to one central processing facility, as opposed to processing sour gas at a number of facilities throughout the area, a lower environmental impact would result having regard for surface disturbances entailed by railroad, sulphur shipping facilities, roads, and sulphur storage. Also, the applicant stated that the environmental concerns associated with sulphur storage and handling would remain concentrated in one area by processing the additional reserves at its plant.

Canterra concluded that its proposal would therefore be in the public interest and would provide for the most economic, orderly, and efficient development of the reserves from the South Hanlan-Brown Creek area.

7.2 Interveners' Views

The interveners were not involved in the previously heard pipeline applications, and did not raise objections to the concept of the large inter-connected system proposed by Canterra. Also, they appeared satisfied that the Ram River plant was a suitable location for such processing.

7.3 Board's Views

The Board considers the proposal to sustain the load level at the Ram River plant, by tying in new sour-gas reserves to replace the declining supply from older pools, to be economically efficient, orderly, and generally in the public interest.

8 TECHNICAL AND CONSERVATION MATTERS - RAM RIVER PLANT

8.1 Views of Canterra

Canterra stated that its proposal to process further gas reserves would have the advantage of using spare capacity at its Ram River gas plant while it would not affect the level of gas and hydrocarbon liquids conservation presently being achieved. The applicant testified that it would be able to maintain the volume of gas flared to within 0.5 per cent of the total volume delivered to the plant.

With respect to IL 80-24 and the level of sulphur recovery that should be specified, the applicant contended that, since the application would neither significantly modify the plant nor prolong its life, the sulphur recovery requirements should remain as stipulated in its approval (that is 98.0 per cent). However, Canterra subsequently proposed a 98.4 per cent annual recovery efficiency and a quarterly recovery of not less than 98.0 per cent of the sulphur contained in the gas delivered to the plant. The increased sulphur recovery would represent a modestly higher level of conservation of sulphur and a correspondingly modest decrease in SO_2 emissions compared with that specified in the present approval.

Canterra testified that the plant, through good operating practice and optimization, had achieved a 98.4 per cent recovery efficiency in 1981. Also, by the addition of a gas/gas heat exchanger, increasing the rate of change-out of the catalyst beds, and improving some burner designs, it was confident that the 98.4 per cent level could be maintained. The applicant also said that it was investigating the use of a new sophisticated catalyst in the hope that sulphur recoveries could be further improved in a cost-effective manner.

Regarding the allowed difference of a 0.3 per cent lower sulphur recovery for any given quarterly period compared to the annual period, Canterra testified that it would be willing to commit to a 98.1 per cent quarterly and a 98.4 per cent annual recovery efficiency, thus satisfying the requirement of IL 80-24.

Canterra recognized that a new plant of the capacity of the Ram River plant would be required by IL 80-24 to achieve a 99.0 per cent annual sulphur recovery efficiency. However, the applicant stated that it knew of no technology available that could achieve recovery of more than 98.4 per cent without the installation of a second-generation TGCU. The applicant pointed out that Sulfreen type tail gas clean-up facilities which were "state-of-the-art" units at the time, had been in operation at

the plant since 1972-73, and that these units had achieved a 98.4 per cent sulphur recovery over the past year. It stated that although second-generation TGCUs capable of 99+ per cent recoveries are now available, the capital costs to retrofit the Ram River plant with any such units would be extremely high in relation to any benefits that might be obtained. For example, the Fluor report submitted by Canterra, indicated that the capital costs of a second-generation TGCU at Ram River would be from $60 million to $135 million. There would also be commensurate increases in operating costs with attendant higher gas processing costs, reduced economic return to everyone including the public, and a very modest gain in sulphur recovery. By comparison, the applicant indicated that its proposed modifications would result in capital costs from $4 million to $5 million with negligible increase in operating costs.

Canterra estimated that the cumulative SO_2 emissions from the plant over its life would be approximately 516 000 tonnes. When asked if it would be willing to commit to limiting future cumulative-total emissions from the plant to that total, Canterra replied that it could not predict what future gas reserves might be found and possibly tied into the plant and was therefore not willing to commit to any absolute SO_2 emission total.

8.2 Interveners' Views

M. Kostuch pointed out that the processing of South Hanlan-Brown Creek gas reserves at the Ram River plant represented an additional throughput of some 23 per cent over and above the amount available from fields presently tied to the plant. It was her contention that in accordance with IL 80-24 the applicant should be required to achieve a 99.0 per cent annual sulphur recovery efficiency. In closing argument, M. Kostuch stated that, although she was not opposed to a recovery level of 98.4 per cent, the Board should consider approval of 0.1 to 0.3 per cent higher equivalent to 98.5 to 98.8 per cent sulphur recovery on an annual basis. Additionally, she contended that Canterra's proposal to operate at a sulphur recovery efficiency of 98.4 per cent did not really reflect an improvement in the Ram River plant, as it was already capable of that recovery level even without the proposed modifications.

M. Kostuch stated that she was not convinced that 99+ per cent sulphur recovery would not be economic. In support of her case she pointed out that certain of the second-generation TGCUs achieved such high sulphur recovery levels that the need to incinerate the waste gases could be eliminated. She maintained that the resultant fuel gas savings would be significant.

M. Kostuch recommended that Canterra be required to install a gas/gas heat exchange system prior to the processing of any additional reserves and that a report be filed with the Board, as soon as possible, on the effectiveness of the new catalyst mentioned by the applicant.

The other interveners, in general, were not opposed to the granting of the application at a 98.4 per cent recovery level. However, they requested that certain requirements be met as a condition of, or prior to, approval. FAN and Fish and Game requested that the applicant report to the Board as soon as possible on the success of the proposed plant modifications and that, on the basis of that report, the Board consider implementing a higher sulphur recovery level. The interveners said that any such reports should be made available to them through the Board. Additionally, these interveners requested that the Board review plant operations after two years to determine whether the sulphur recovery efficiency was appropriate, having regard for the availability of new technology.

8.3 Board's Views

It is significant that the Canterra plant, the largest sour-gas plant in the province, with a rated sulphur inlet capacity of about 4660 tonnes per day of sulphur, has operated since its inception 10 years ago with a Sulfreen tail-gas unit with a specified sulphur recovery efficiency level of 98.0 per cent. The Board also notes that Canterra has been successful in upgrading operating procedures to a point where it can now guarantee 98.4 per cent efficiency with the existing tail-gas installation. It is, moreover, implicit in this undertaking that given the flexibility of 0.3 per cent in the quarterly required efficiency, the plant operator would have to sustain operating efficiencies in excess of 98.5 per cent in some quarterly periods in order to offset other quarterly periods where the efficiency might be only 98.1 per cent. On the whole, the Board is satisfied and believes that the interveners generally indicated similar satisfaction, that the plant is being operated in a very efficient manner with respect to sulphur recovery. This conclusion seems valid both in terms of the average annual efficiency of the operation, as well as that of very short-term (hourly) plant instabilities. It is appropriate that the plant approval should be amended to reflect this plant efficiency capability. The Board does not, however, believe that it would be in the interest of the plant operators or the public to impose a cumulative SO_2

emission limit in the approval, as this might restrict the options for efficient processing of future gas discoveries in the area. On the basis of the evidence presented, the Board therefore believes that the substantial additional capital costs (probably in excess of $100 million) needed to retrofit the tail-gas unit with the objective of 99+ per cent sulphur recovery clearly lacks economic merit. The Board is convinced that it would not be in the public interest to require these investments unless environmental evidence definitely indicated the need for them. The Board also notes that the practice of its staff in regularly reviewing operations to ensure that modern, technically sound methods are being applied, ensures that plant operations continue to meet high standards.

The Board endorses the proposal by Canterra to pursue further plant control refinements such as: installation of a gas/gas heat exchanger to improve reaction efficiency, the practice of appropriately frequent catalyst change-out to ensure efficient catalyst kinetics, and the possibility of introducing more efficient new types of catalysts. The Board regards these as refinements on the overall plant complex that, although worthy of review by the Board staff, would be inappropriate as conditions in the Board's approval.

9 ENVIRONMENTAL MATTERS - RAM RIVER PLANT

9.1 Views of Canterra

Canterra submitted a report entitled "Ram River Gas Plant Annual Environmental Review", which summarized the plant operations, monitoring requirements, environmental programs, and plant alterations that occurred in 1981. A number of other reports dealing with ambient air monitoring history, abundance of certain lichen species, water quality and stream biomonitoring, projections of SO_2 impact on Swan Lake, long-range atmospheric pollutant transport modelling, estimating of local SO_2 depositions, and sulphur dust impact on soils were also introduced by expert witnesses in support of the position that only minor environmental damage in the near vicinity of the plant was demonstrable to date. The main environmental effects were attributed to airborne elemental sulphur dust from sulphur-handling facilities, and certain uncontrolled releases or seepage from waste-water retention ponds. The applicant testified that it had recently allocated a large amount of capital to rectify these problems and to repair damage. These programs were described in greater detail in the applicant's annual report.

Meteorological diffusion studies submitted by the applicant predicted annual SO_2 deposition rates of 1 to 4 kilograms per hectare (kg/ha). Further, the applicant stated that only 1.9 per cent of the total SO_2 emissions from the plant were predicted to come to ground within a 50 km radius of the Ram River site.

The applicant testified that it had, in conjunction with Gulf, commissioned a study by the Northern Forest Research Centre (NFRC) of the Canadian Forest Service to monitor the short- and long-term effects of SO_2 emission on flora, and to study the effect of sulphur dust on soil chemistry and tree physiology.

Canterra argued that in view of its recent large capital expenditures towards environment protection, and the further evidence from the meteorological diffusion models that local deposition of SO_2 was very small, a sulphur recovery level in excess of 98.4 per cent was not warranted from an environmental viewpoint.

9.2 Interveners' Views

The interveners commended the applicant on initiating, jointly with Gulf, the study by the NFRC referred to in section 9.1, but maintained that the other studies submitted by Canterra were of too short a duration to detect the possible adverse effects of chronic, low-level SO_2 deposition on surrounding lands, forests, streams, and lakes. In contrast to the annual deposition rates of 1 to 4 kg/ha calculated from theoretical meteorological diffusion models, M. Kostuch submitted evidence from preliminary experiments involving soil canister measurements in the vicinity of the Canterra and Gulf plants, which indicated sulphur deposition attributed to SO_2 averaging 62 kg/ha over a 3-1/2-month period. She contended that these measurements should carry greater weight in projections of potential SO_2 deposition than the meteorological predictive estimates.

Based on their concerns about the conflicting evidence regarding localized fall-out of SO_2 and also their concern for potential adverse effects of long-term low-level SO_2 deposition rates, the interveners proposed that the combination of plant sulphur balance data, offsite sulphur monitoring data, and the biophysical monitoring results including those of the NFRC program, be made available for public scrutiny.

The other interveners supported the proposal by M. Kostuch that an environmental committee representing industry, government, and the public be formed to recommend and monitor environmental studies and to report to government accordingly. They further requested that the Board voice support for such a recommendation in its decision.

9.3 Board's Views

The Board does not accept that the soil canister studies provide convincing proof of environmental stress. Bearing in mind the preliminary nature of these studies and the weight of contrary evidence stemming from trace isotope studies, the NFRC preliminary reports, and meteorological diffusion predictions, the Board believes that a relatively low SO_2 impingement has occurred to date. However, the Board notes that some effects from sulphur dust escape and waste-water seepage near the plant has had some adverse effects and measures are being taken to correct it.

The Board has considered M. Kostuch's proposal that a company-funded environmental research and monitoring advisory committee be established to review existing programs, to recommend new programs, to review the information collected, and to report to the Board and Alberta Environment. The concept of effective communication between plant operators, nearby residents, and government agencies is heartily endorsed by the Board and indeed, is judged to be essential. While it recognizes that Gulf has agreed to the proposed committee for its Strachan plant, the Board is not convinced that the specific plan proposed by M. Kostuch should be imposed on Canterra. The Board believes it would be much more effective if the parties voluntarily agreed on a specific approach and it would be fully prepared to assist in this process if requested.

10 SUITABILITY OF PROCESSING NEW SOUR-GAS RESERVES AT THE GULF STRACHAN PLANT

10.1 Views of Gulf

Gulf claimed that its application and that of Canterra represented the most practical approach to the development of new sour-gas reserves in the foothills area from the point of view of utilization of existing facilities, lowest cost, and environment protection.

Gulf stated that approval of its application would allow for the processing of gas from several producing areas not currently serviced by the Strachan gas plant. The applicant indicated that its proposed plan would allow it to increase the loading of its Strachan plant from the current level of about 33 per cent to in excess of 66 per cent, without need to increase the maximum raw gas and H_2S inlet rates presently specified in its approval.

Gulf requested that the Board give interim approval for the immediate increment of 306 x 10^3 m^3 per day of Chedderville gas at the currently approved sulphur recovery efficiency level of 97.0 per cent. It was Gulf's position that the processing of Chedderville gas did not represent a significant life extension of the processing plant nor would it provide significant economic benefit, as it was owned by Esso and would be processed by Gulf on a cost-of-service basis. Additionally, Gulf stated that Esso had sales contracts for late 1982 and the applicant therefore requested that the Board consider expeditious approval of that portion of its application. The remainder of the applied-for gas amounting to a maximum of about 4500 x 10^3 m^3 per day and declining to about 1350 x 10^3 m^3 per day would not be processed until such time as tail-gas processing equipment capable of increasing the annual sulphur recovery to at least 98.4 per cent had been installed and was operable.

Gulf submitted that, in conjunction with the various pipeline applications and the Canterra proposal, its application represented a vehicle to tie two major plants together as an integrated operating system for currently producing and new gas fields located in the foothills trend. This integrated system would probably eliminate the need to construct any additional new plants in the environmentally sensitive foothills area.

10.2 Interveners' Views

The interveners were satisfied that the Strachan gas plant was a suitable location for such processing and did not oppose the proposed modifications of the plant.

10.3 Board's Views

The Board considers the Gulf application, in combination with the Canterra application and the related pipeline applications, to be a suitable and efficient means of developing sour-gas resources in the regions described.

11 TECHNICAL AND CONSERVATION MATTERS - STRACHAN PLANT

11.1 Views of Gulf

Gulf stated that the proposed scheme would utilize spare capacity at its Strachan gas processing plant and, therefore, would not affect hydrocarbon conservation levels presently being achieved by the plant. It submitted that the processing of the additional reserves other than the Chedderville gas at the Strachan plant would alleviate current turn-down difficulties, thereby restoring operations to a more efficient load level.

Gulf investigated the feasibility of achieving a 98.4 per cent annual sulphur recovery efficiency and indicated that it was prepared to commit the additional capital necessary to meet the requirements of IL 80-24. Of necessity, its project economics assumed that Canterra's application would be approved and the associated pipelines built. Gulf stressed that without the revenue generated by the production of the additional reserves, it could not economically justify the installation of a TGCU at the Strachan gas plant.

Gulf stated that it was considering either the MCRC or Sulfreen TGCU processes as means of meeting the 98.4 per cent sulphur recovery objective. The applicant stated that although the vendor for the MCRC process had guaranteed a 98.5 per cent recovery efficiency, there was only one such plant operating in North America and, therefore, it was difficult to evaluate the capability of the process. On the other hand, Gulf pointed out that there were many Sulfreen units in operation and the track record was good.

When asked whether Gulf would consider installing the gas/gas heat exchange system and the catalyst described by Canterra, Gulf stated that, although it was interested in the catalyst, it would expect only limited improvement in sulphur recovery with either proposal. Gulf explained that these modifications were only desirable if substantial amounts of carbon-sulphur compounds were present in the acid-gas stream and that this was not the case at its Strachan gas plant.

11.2 Interveners' Views

Generally, the concerns of the interveners and their recommendations were the same as those expressed in Section 8.2 of this report except with regard to the sulphur recovery level. The interveners noted that Gulf's proposal met the requirements of IL 80-24 and they were satisfied with Gulf's undertaking to achieve 98.4 per cent annual sulphur recovery efficiency. M. Kostuch requested that, as a condition of an approval, the applicant should not process any of the new reserves except those from Chedderville until a TGCU had been installed.

11.3 Board's Views

The Board considers the proposal by Gulf to install a TGCU and the contingent increased load levelling of the plant to be desirable on both technical and conservation grounds. Also, in view of acceptance by interveners, who otherwise focussed on environmental concerns, the Board sees no reason to oppose the tying-in of the Chedderville gas to the existing plant as soon as is practical.

12 ENVIRONMENTAL MATTERS - STRACHAN PLANT

12.1 Views of Gulf

The applicant took the position that the proposal to increase sulphur recovery from 97 per cent to 98.4 per cent was both practical and timely in view of the application to process new sour-gas reserves.

In addition to the normal monitoring activities required by the plant approval, Gulf pointed to studies of the relative abundance of trace sulphur isotopes in the environment, special studies of plume dispersion and meteorology, surface- and ground-water quality, and other as-yet-incomplete studies as being indicative of the adequate environmental protection presently afforded by controls in place at the Strachan plant. While minor damage to the most sensitive lichen and moss species had been found near the plant, these were confined to a distance of 100 metres from the plant boundary, and attributed to dusting from the sulphur-handling facilities, or possibly aerially applied lime. A small area near the railroad and sulphur blocks had also exhibited leaf damage, possibly caused by sulphur dust or fumigation from sulphur block fires. Careful monitoring and corrective measures were being carried out. This being the case, the applicant submitted that a compelling case for the imposition of higher sulphur recovery efficiency could not be made at this time. Gulf expressed a willingness to participate in an environmental committee, and agreed that the interveners should have access to any reports the Board might require, provided that the Board would undertake the dissemination of these.

12.2 Interveners' Views

The views of the interveners were identical to those expressed with respect to the Canterra application.

12.3 Board's Views

The Board is satisfied that installation of tail gas clean-up at the Strachan plant will ensure highly efficient sulphur recovery, and will allow the plant to be utilized for further loading of gas from the applied-for reserves and future new sour-gas reserves with environmentally acceptable operation. The Board notes that biological monitoring has indicated only limited stress from the current facilities which have been in operation since 1971. Having regard for all factors, the Board is satisfied that the Gulf proposal offers optimum environment protection. With respect to the environmental committee, the Board's views are the same as those expressed in section 9.3.

13 DECISION

Application 810650 by Canterra

Having considered all the evidence, the Board finds that the Canterra application is in the public interest having regard for the technical, conservation and environmental aspects and is, therefore, prepared to grant the application subject to receipt of the required approval of the Minister of the Environment.

Application 810849 by Gulf

Having considered the technical, conservation, and environmental aspects of the Gulf application, the Board is similarly prepared to grant the application subject to receipt of the necessary approval of the Minister of the Environment with respect to environmental matters and subject to the following conditions:

a. That, for an interim period, Chedderville gas may be processed at the currently-approved minimum quarterly sulphur recovery efficiency level of 97.0 per cent.

b. That gas from fields other than Strachan, Crimson, and Chedderville shall not be processed at the Strachan plant until the Board has approved, pursuant to section 15.050(4) of the Oil and Gas Conservation Regulations, the installation of equipment capable of ensuring an annual sulphur recovery efficiency level of 98.4 per cent.

c. That after commencement of gas production from the Jupiter, Blackstone, Brown Creek, Big Horn, Cordd, and Voyager areas, and the Ricinus and Stolberg fields, all of the gas produced from wells supplying the plant that is not required for lease fuel shall be gathered and processed for the quarterly recovery of not less than 98.1 per cent of the sulphur contained in the gas delivered to the plant.

DATED at Calgary, Alberta, on this 10th day of June, 1982.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard

N. Strom, P.Eng.

R. G. Evans, P.Eng.

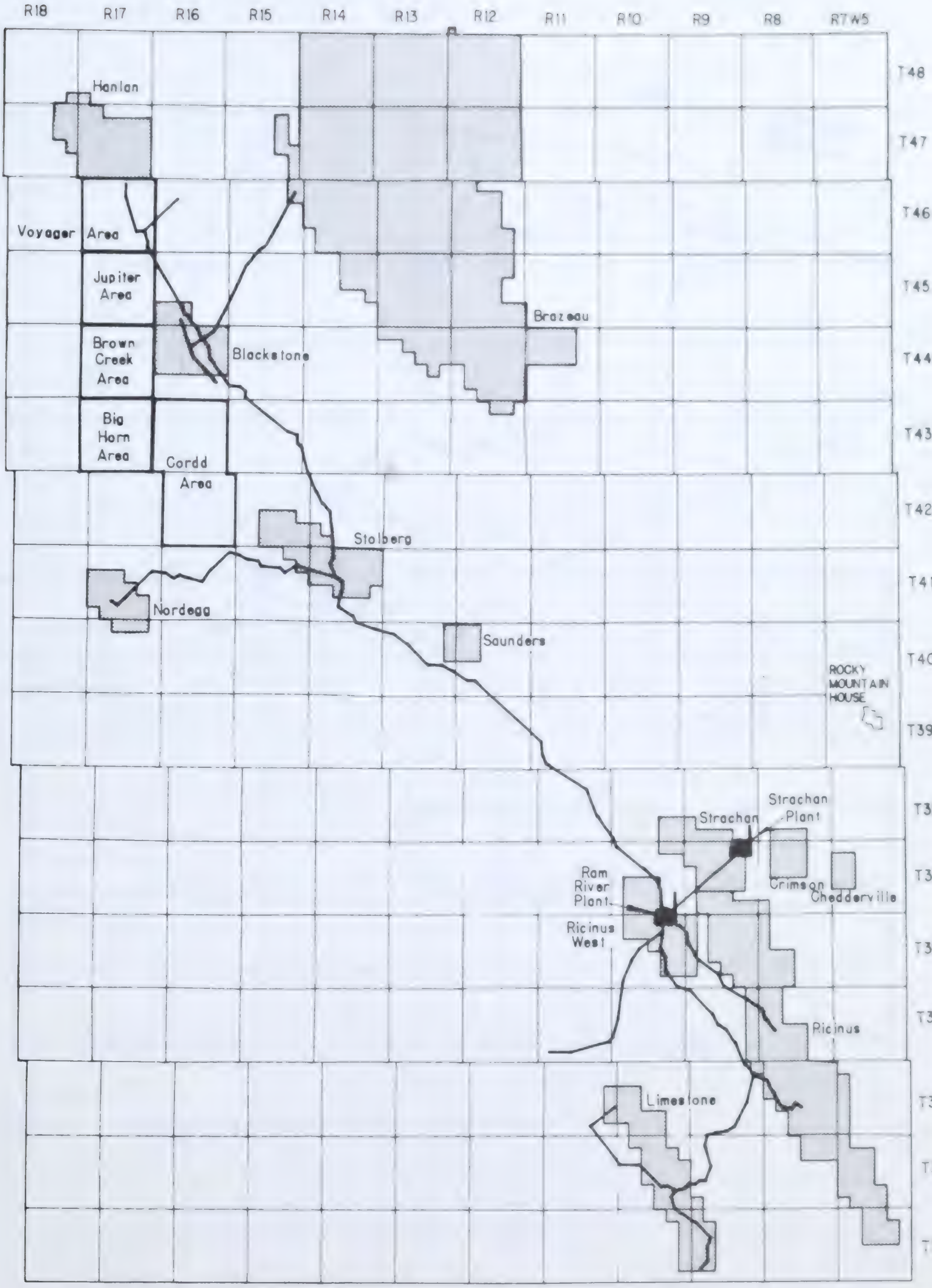
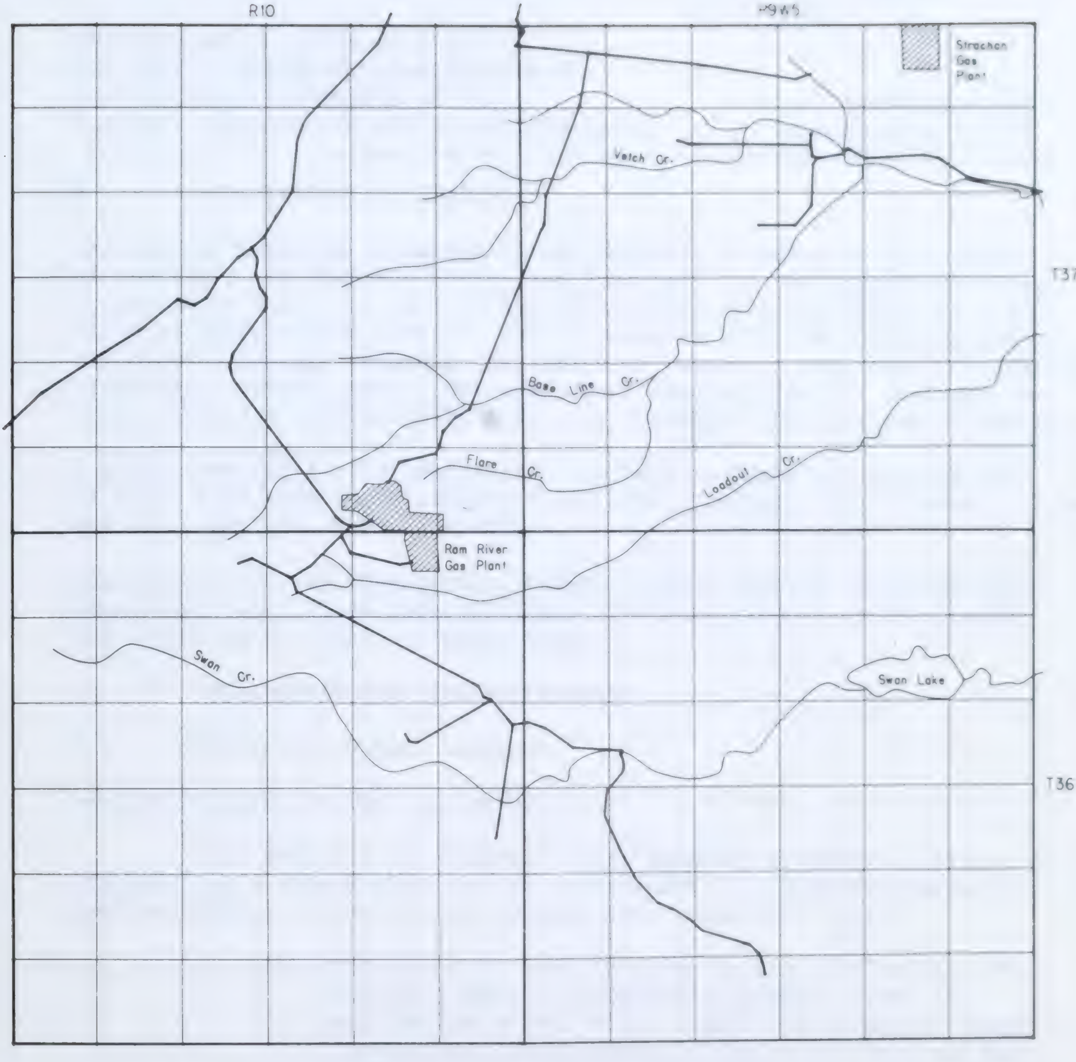


FIGURE 1 SOUTH HANLAN-RICINUS AREA (Fields, Pipelines, Plants)



Roads ————

FIGURE 2 STRACHAN-RICINUS AREA

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

DECISION ON AN APPLICATION BY
THE CITY OF EDMONTON (EDMONTON POWER)
TO EXPAND THE BOUNDARIES OF ITS
ELECTRIC DISTRIBUTION SYSTEM SERVICE AREA

Decision 82-16
Application 810819

1 APPLICATION AND HEARING

The City of Edmonton (Edmonton Power) applied, pursuant to section 26 of the Hydro and Electric Energy Act (the Act), to the Energy Resources Conservation Board (the Board) for orders expanding the limits of its electric distribution service area to coincide with its corporate limits and correspondingly reducing the limits of TransAlta Utilities Corporation's (TransAlta) service area. The additional area applied for includes the area within the city's limits served by TransAlta and is shown on the figure.

A public hearing of the application was held in Edmonton, Alberta, on 22 April 1982 with Board members V. Millard, Chairman, G. J. DeSorcy, P.Eng., and C. J. Goodman, P.Eng., sitting.

TransAlta Utilities Corporation, Genstar Cement Limited, and Fiberglas Canada Inc. each filed interventions. The participants at the hearing are listed in the Table of Appearances.

2 CONSIDERATION OF THE APPLICATION

2.1 Matters of Public Interest

Section 26(3)(b) of the Act states:

"(3) When a local authority that owns and operates an electric distribution system applies for an enlargement of its service area to include additional land in its municipality, the Board shall

> (b) in respect of land included in the service area of another electric distribution system, grant the application unless after a public hearing the Board finds compelling reasons in the public interest not to do so, in which case the Board with the approval of the Lieutenant Governor in Council may deny the application in whole or in part,

and when the Board grants an application to which clause (b) applies it shall stipulate any terms and conditions it considers reasonable including a stipulation of the date on which the alteration of the service areas comes into force."

None of the parties at the hearing argued that there were compelling reasons in the public interest to justify not granting the application for the transfer of the additional service area requested by Edmonton Power. The Board itself finds no compelling reasons not to transfer the area and therefore is prepared to grant the application.

TABLE OF APPEARANCES

Principals and Representatives (Abbreviations used in Report)	Witnesses
The City of Edmonton (Edmonton Power) P. A. Smith	E. F. Kyte, P.Eng. A. Sadesky, P.Eng. D. J. Pelletier, P.Eng.
TransAlta Utilities Corporation (TransAlta) M. H. Patterson, Q.C. E. J. McCoy	H. G. Schaefer G. D. Lyons, P.Eng.
Genstar Cement Limited (Genstar) G. E. Bowker	
Fiberglas Canada Inc. (Fiberglas Canada) D. R. Thomas	
Energy Resources Conservation Board staff (Board staff) K. F. Miller, Board Solicitor J. Wilson, P.Eng. K. Kendrick M. MacRae	

2.2 Terms and Conditions

The parties to the hearing presented their views on the terms and conditions which should be applied to the service area transfer. Edmonton Power requested 1 August 1982 as the transfer date. TransAlta stated it could agree with the proposed transfer date provided it was compensated for fixed charges on its Keephills 1 and 2 generating units. In the absence of such an arrangement, TransAlta contended that the transfer should be delayed five years so that it might handle the electricity generated by, and the financial arrangement related to, the Keephills 1 and 2 units in the manner anticipated when the units were applied for. The Board believes this is a matter which might be an aspect of compensation but is not one which should dictate the transfer date. Since all evidence suggested that the transfer could efficiently take place by 1 August 1982, the Board considers it reasonable to stipulate that as the date on which the alteration of the service areas comes into force.

TransAlta requested as a condition of the transfer that all existing TransAlta contract holders within the transferred area have all the terms of their contracts honoured by Edmonton Power. Also, Genstar and Fiberglas Canada each requested that the Board include as specific conditions of its order that Edmonton Power honour all of the terms of their existing contracts with TransAlta. Edmonton Power stated it intended to honour all power supply contracts and could accept such a condition. The Board believes it reasonable to stipulate as a condition to the transfer order that Edmonton Power honour all existing individual power supply contracts that are currently in place between consumers in the area and TransAlta.

2.3 Compensation

Section 26(4) of the Act allows for the provision in the transfer order for compensation when the service area of an electric distribution system is reduced and when the Board considers such provision suitable. The Board believes that in this instance Edmonton Power should pay compensation to TransAlta.

The Board notes that both parties are progressing in negotiations towards an agreement on this matter and consequently is not prepared at this time to condition its order by specifying the matters in respect of which compensation is payable. Rather, the Board, pursuant to section 26(5) of the Act, is deferring until 1 March 1983 the addition to the order of any provisions respecting compensation in order to give the parties the opportunity of making a voluntary agreement as to compensation to be paid. After that date, if the Board is informed by either party to the transfer that an agreement could not be made, the Board would call a hearing and require the filing of additional evidence. Following that hearing the Board would add provisions respecting compensation to the transfer order.

3 DECISION

The Board grants the application transferring the service area shown on the figure from TransAlta to Edmonton Power. It will stipulate as conditions of the transfer that the alteration come into force 1 August 1982, and that Edmonton Power honour all terms of existing TransAlta service contracts in the area. The Board defers to 1 March 1983 the consideration of addition of compensation provisions.

ISSUED at Calgary, Alberta, on 21 May 1982.

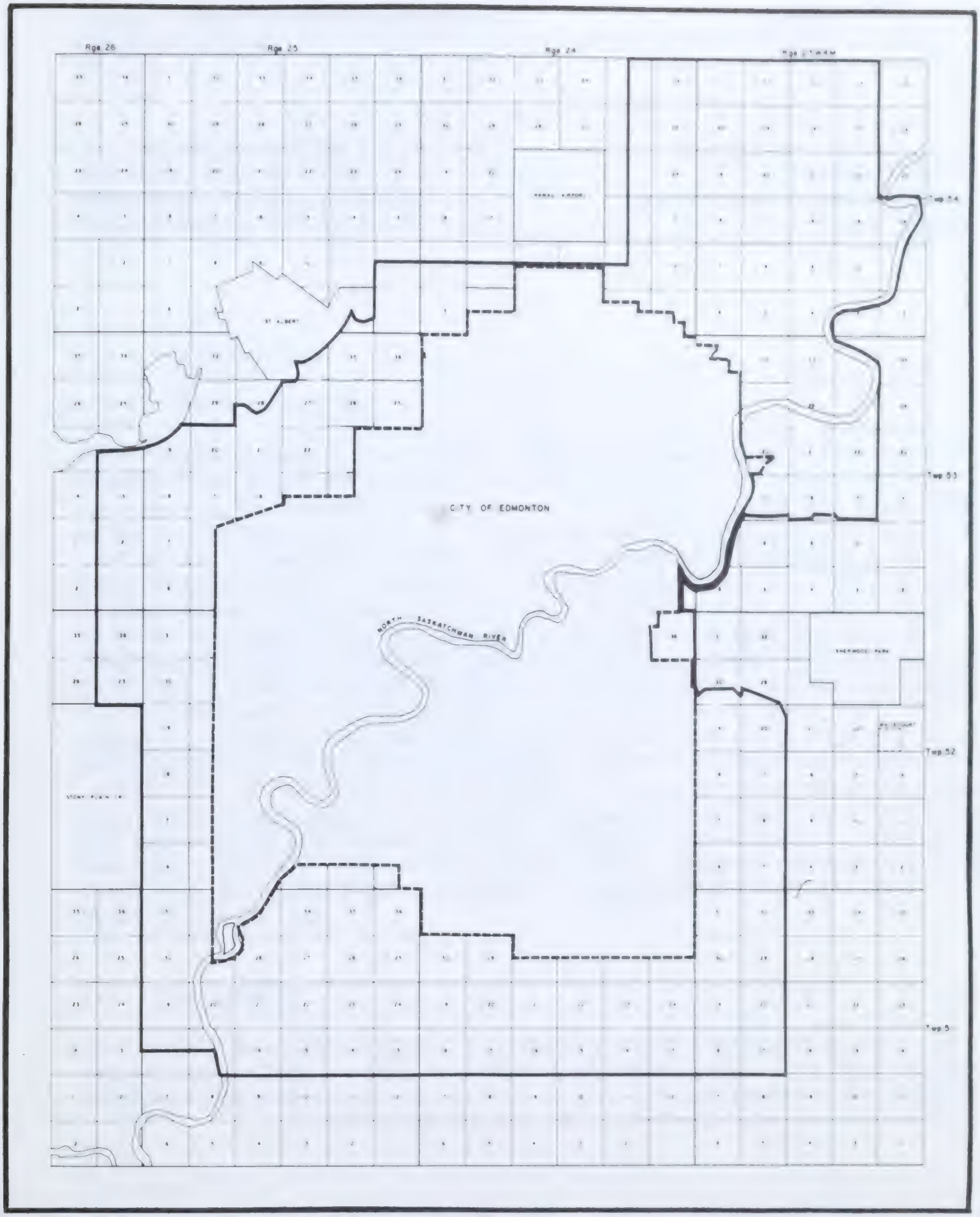
ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

G. J. DeSorcy, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member



PROPOSED CITY OF EDMONTON SERVICE AREA
EXISTING CITY OF EDMONTON SERVICE AREA

CITY OF EDMONTON ELECTRIC DISTRIBUTION SERVICE AREA

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

GULF CANADA RESOURCES INC.
SOUR GAS, FUEL GAS AND
SALTWATER DISPOSAL PIPELINES
SHAW-MOUNTAIN PARK AREAS

Decision 82-17
Applications 811041, 820204
and 820205

1 INTRODUCTION

1.1 The Applications

Gulf Canada Resources Inc. (Gulf) applied to the Energy Resources Conservation Board pursuant to the Pipeline Act for a permit to construct a 29 kilometre (km) pipeline to transport sour gas from three wells in the Shaw field and a 17 km pipeline to transport sour gas from four wells in the Mountain Park field to a central compressor station in legal subdivision 2 of section 28, township 48, range 21, west of the 5th meridian. Approximately 22 km of 219.1-mm outside diameter (OD) pipeline was applied for to transport the sour gas from the proposed compressor to Gulf's Robb gas plant. Gulf also applied for a permit to construct a fuel gas pipeline system to supply fuel gas from the plant to the compressor station and line heaters on the proposed sour gas gathering system. The fuel gas lines would be installed adjacent to the sour gas lines. Gulf also applied for a permit to construct approximately 8.35 km of 114.3-mm OD pipeline to transport sour produced water from the Robb gas plant to a water disposal well in Lsd 15-10-49-19 W5M. The applied for facilities are shown on the attached figure. The proposed sour gas pipelines would transport gas with a maximum hydrogen sulphide (H_2S) content of 33.9 mol/kmol and be classified as Level 1[a] and Level 2[b] facilities.

1.2 Background

Gulf's Robb gas plant, which is currently under construction, was the subject of a Board hearing in Edson in December 1980. The main issue considered by the Board was whether or not the gas reserves in the area

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a Sour gas facilities which have a potential release volume of less than 300 m^3 of H_2S (as defined by ERCB Interim Directive 81-3).

b Sour gas facilities which have a potential release volume of less than 2000 m^3 of H_2S (as defined by ERCB Interim Directive 81-3).

could be produced without significantly jeopardizing the interests of coal operators in the area. After reviewing the evidence submitted by coal operators and Gulf at the hearing, the Board decided that both resource development operations could co-exist in the area as long as all parties involved co-operated in their planning. The Board subsequently approved Gulf's plant application in ERCB Decision Report 81-1. The Board agreed that it would give notice to the coal lease holders upon receipt of pipeline applications which may have some effect on their operations.

1.3 Intervention

Mercoal Minerals Ltd. (Mercoal), a subsidiary of Manalta Coal Ltd., submitted a written intervention regarding Gulf's applications. The intervention outlined Mercoal's plans to construct a coal washing plant adjacent to Gulf's proposed Shaw sour gas pipeline and asked the Board to address the issue of compatibility of Gulf's proposed pipeline and Mercoal's proposed coal plant.

1.4 The Hearing

Gulf's applications were considered by the Board at a public hearing on 11 May 1982 in Edson, Alberta, with G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng. and N. A. Strom, P.Eng., sitting.

The following table lists the persons who appeared at the hearing.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Gulf Canada Resources Inc. (Gulf) C. Johnson	J. Law, P.Eng. J. Spoor, P.Eng. M. Polet
Mercoal Minerals Ltd. (Mercoal) R. Melrose	R. M. Shaneman, P.Eng.
Alberta Environment T. Bossenberry	
Energy Resources Conservation Board staff M. J. Bruni G. C. Dunn, P.Eng. B. C. Hubbard, P.Eng. D. Markland	

2 ISSUES

The Board considers the main issues to be:

- routing of the proposed lines,
- environmental impact,
- compatibility of the proposed sour gas pipeline and the proposed coal washing plant having regard for safety,
- technical design aspects.

3 APPLICANT'S VIEWS

Gulf stated that its main consideration in selecting the proposed pipeline routes were topography, environmental impact and impact on coal resource development. In response to questioning by Alberta Environment, Gulf explained the advantages and disadvantages of a number of alternative routes that had been considered. Some of the alternatives considered would have less environmental impact than the proposed route in terms of creek crossings and other matters but were undesirable because of impact on coal resources. Other alternatives were rejected because of topographical constraints such as steep sideslopes, and unstable soil conditions. Gulf stated that the proposed pipeline route was the best compromise to minimize environmental impact, minimize impact on coal development and avoid areas where the topography would result in difficulty for installing and operating the line. Gulf emphasized that environmental impact could be minimized by building the pipeline during the period 1 June to 30 September which would avoid impact on the stream fishery and allow time to establish vegetation and reduce stream bank erosion in the spring of next year.

Regarding compatibility from a safety viewpoint of the proposed sour gas pipeline and Mercoal's proposed coal washing plant, Gulf proposed to install two linebreak valves near the plant site to provide a Level 1 facility and the setback distance from Mercoal's plant buildings to meet the required minimum distance specified in the ERCB's Interim Directive 81-3. Gulf indicated that the route location in the vicinity of the plant was considered optimum in that it avoided difficult sideslope situations and, unless further setback was thought necessary, it would not wish to alter the proposed route. Gulf added that it believed the proposed Level 1 pipeline was not incompatible with the proposed coal washing plant and that it could be operated safely in conjunction with Mercoal's operations. In response to questions regarding additional measures to either further protect the integrity of the proposed pipeline or give warning of a gas leak near the Mercoal plant, Gulf stated that it intended to construct necessary load bearing conduits at the three known road crossings to the coal plant, and would investigate the need for deeper burial of the line, the permanent fencing or otherwise marking of the right of way, and the continuous operation of H_2S detection equipment along the right of way. Gulf also committed to incorporate into its emergency contingency plan for the proposed sour gas line measures to ensure the safety of Mercoal employees in the event of a pipeline failure near the proposed coal washing plant.

Gulf was questioned regarding the technical design of the proposed sour gas pipelines particularly as it related to internal corrosion. Gulf submitted that by maintaining high flow velocities in the pipeline, any free liquids in it would be carried with the gas as a mist and would not be allowed to cause local internal corrosion by accumulating at low spots along the route. With the high flow velocities and the proposed chemical inhibition program, Gulf does not anticipate a corrosion problem in transporting the wet sour gas.

4 VIEWS OF MERCOAL

Mercoal Minerals Ltd. is a major coal lease holder in the Robb-Hanlan area. Mercoal intervened in the hearing to express its concern respecting the position of Gulf's proposed pipeline relative to the location of Mercoal's proposed coal cleaning facility.

The coal cleaning facility, to be located near the old Mercoal townsite has been recently disclosed to the Board through an application for an approval to construct a coal processing plant and a permit to develop a mine site.

Mercoal indicated that it was planning to have construction under way within two years and the plant operational by mid-1986. Mercoal officials indicated that construction of the plant facilities would involve a peak work force of upward of 500 persons who would be located in a camp approximately 200 metres from the sour gas pipeline being proposed by Gulf.

In addition, Mercoal indicated that during operation the plant would employ approximately 125 persons per shift with the majority being located at the washplant some 200 metres from the proposed Gulf pipeline.

It was Mercoal's position that it did not have the in-house expertise to assess the risk from the sour gas pipeline. Company representatives also indicated that they did not want to be in a position of having to make major relocations of facilities at a later date to satisfy Board requirements respecting the relative locations of manned industrial operations and sour gas pipelines. Therefore, they asked that the Board review the plans to ensure that the Board's rules of compatibility were satisfied and that both the Gulf and Mercoal facilities could co-exist safely in the locations applied for. Mercoal indicated that there was limited flexibility in the location of its facilities within the proposed plant site area.

Mercoal agreed that the access roads could be adjusted somewhat if necessary in order to intersect the pipeline right of way at right angles. Mercoal also agreed that, if deemed necessary and if appropriate approvals could be obtained, it would pre-build site access roads to ensure that Gulf designed the road crossings with full knowledge of the road locations and to eliminate construction over a "hot" sour gas pipeline.

5 VIEWS OF THE BOARD

The Board has reviewed the applications and is generally satisfied with regard to the technical design and routes of the pipelines being applied for. The Board notes that the pipeline has been designed and routed after discussions with other land users as well as agencies concerned with environmental impact.

With regard to environmental considerations, the Board believes that the impact of the pipelines can be minimized if they are installed at the appropriate time of year using proper construction methods and provided careful attention is given to the development of reclamation procedures. While they would have some environmental impacts, the Board believes that, on balance, the routes selected are satisfactory.

With regard to technical considerations, the Board is satisfied that the pipeline has been properly designed and can be operated safely. The Board holds this view even with respect to the line in the vicinity of the proposed Mercoal facility. However, it believes special precautions should be taken to safeguard against the possibility of sour gas releases near the Mercoal property and to minimize the impact in the unlikely event that such a release was to occur. The Board believes that it should have additional information prior to establishing these special precautions. Therefore, it will condition any permit issued to Gulf requiring it to provide to the Board, prior to the commencement of construction, the following information.

(1) An outline and some disclosure of information pertaining to the Emergency Contingency Plan. Of particular interest is a discussion and undertaking with respect to procedures involving Mercoal personnel.

(2) A more detailed evaluation and discussion relating to pipeline security in the vicinity of the proposed plant location. This should include the following considerations:

(a) extra depth of cover,

(b) right of way marking and possible methods of isolating the pipeline from other potentially disruptive activities,

(c) possible H_2S detection methods and benefits of their usage.

Upon receipt of this additional information the Board will stipulate special precautions to be taken in the vicinity of the proposed Mercoal plant.

6 DECISION

Subject to approval from the Minister of Environment with respect to environmental matters, the Board is prepared to issue permits for the applied-for pipelines. The sour gas pipeline permit will be subject to a condition respecting special precautions near the proposed Mercoal Minerals Ltd. plant site.

ISSUED at Calgary, Alberta on 18 May 1982.

ENERGY RESOURCES CONSERVATION BOARD

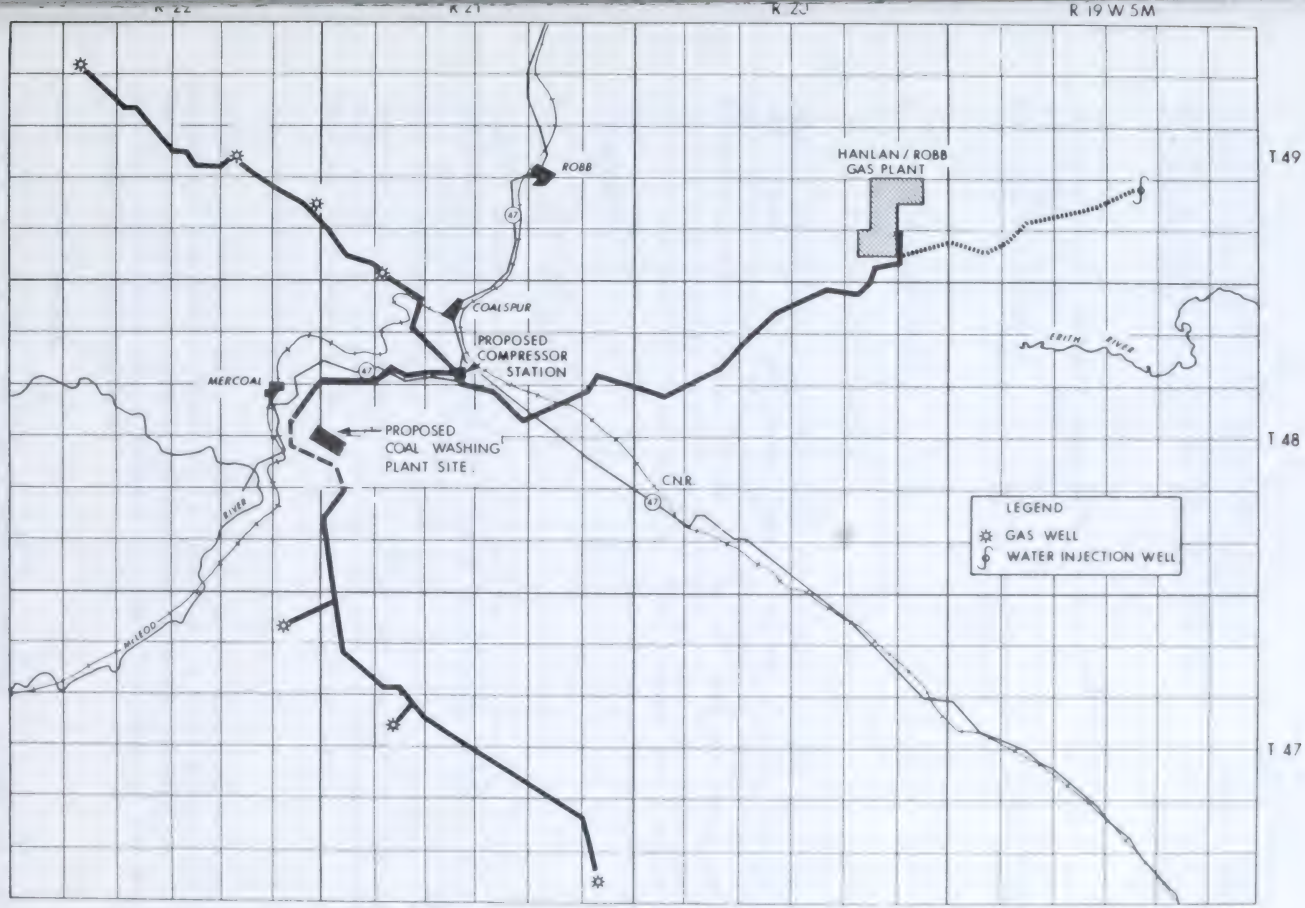
G J DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

V E Bohme

V. E. Bohme, P.Eng.
Board Member

N. Strom, P.Eng.
Board Member



Level 1 sour gas line
Level 2 sour gas lines
Salt water disposal line

GULF CANADA RESOURCES

PROPOSED SOUR GAS AND WATER DISPOSAL PIPELINES

SHAW / MOUNTAIN PARK AREA.

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA CANADA

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY LOMALTA RESOURCES LTD. TO REDUCE THE SIZE OF THE DRILLING SPACING UNIT AND FOR A CHANGE TO A 16 HA TARGET AREA IN ACCORDANCE WITH SU 800

Decision 82-18
Application No. 820150

APPLICATION BY LOMALTA RESOURCES LTD. FOR A LICENCE TO DRILL A WELL IN LSD 15C-15-1-16 W4M

Application No. 820218

1 INTRODUCTION

1.1 Application 820150

Lomalta Resources Ltd. on behalf of itself and the working interest owners and lessees of the northeast quarter of section 15, Township 1, range 16, west of the 4th meridian, applied pursuant to section 4.030 and in accordance with section 15.160 of the Oil and Gas Conservation Regulations for one legal subdivision (Lsd) drilling spacing units (DSU) with target areas as defined by Order SU 800. This change would apply for the production of oil from the Moulton Sandstone of the Lower Mannville Formation.

1.2 Application 820218

Lomalta Resources Ltd. applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations, for a licence to drill a well in the northwest quadrant of legal subdivision 15 of section 15, township 1, range 16, west of the 4th meridian (15C-15 well) having co-ordinates of 4.57 metres south of the north boundary and 797.97 metres west of the east boundary of section 15 (see Figure 1) for the purpose of obtaining production from the Moulton Sandstone of the Lower Mannville Formation.

1.3 Intervention

Murphy Oil Company Ltd. on behalf of itself and the working interest owners of the Coutts Moulton "A" Unit No. 1, and Texaco Canada Resources Ltd., on behalf of itself and working interest owners, of the northwest quarter of section 15, township 1; range 16, west of the 4th meridian, opposed the application.

1.4 The Hearing

A public hearing of the applications was held before the Energy Resources Conservation Board on 30 April 1982 in Calgary, Alberta, with

G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and C. J. Goodman, P.Eng. sitting.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Lomalta Resources Ltd. (Lomalta) R. B. Gair, P.Eng.	A. R. Rallison, P.Geol.
Murphy Oil Company Ltd. (Murphy) R. D. Friesen, P.Eng.	B. Jensen, P.Geol.
Texaco Canada Resources Ltd. (Texaco) D. B. Laustsen, P.Eng.	D. D. Hansen, P.Geol.
Energy Resources Conservation Board staff D. A. Holgate W. Elsner, P. Geol. H.J.W. Piët, C.E.T. M. Semchuck	

1.5 Background

The Coutts Moulton A Pool (A Pool) is separated from the Coutts Moulton C Pool (C Pool) by a fault. The fault trend and other matters relating to pool configuration will be discussed in more detail in later sections of the report.

The existing spacing for oil production from the A Pool is one legal subdivision with the target area centrally located in accordance with section 4.020 (2) of the Oil and Gas Conservation Regulations. This is shown in Figure 1, along with the change in spacing and target area as applied for by Lomalta.

A waterflood pressure maintenance scheme was implemented in 1970 in a part of the A pool by Murphy, who is the unit operator of the Coutts Moulton A Unit No. 1, the boundary of which is shown in Figure 1.

2 THE ISSUES

The Board believes the issues pertaining to the application to be:

- The configuration of the Moulton A Pool.
- The appropriateness of reducing the size of drilling spacing units in the NE 1/4 of section 15-1-16 W4M.

- o The appropriate shift of the target area if reduced spacing is to be approved and having regard for

  i) impact on conservation, and
  ii) impact on equity.

- o The suitability of drilling the proposed well in the applied for location.

3 THE CONFIGURATION OF THE MOULTON A POOL

3.1 Views of Lomalta

Lomalta contended that the A Pool is a long shore sand bar trending in a northeast-southwest direction and dipping to the north. The downdip production limit of the pool is arbitrarily defined by an oil-water contact at 950 m above mean sea level, and the updip limit of the pool is defined by two NNW-SSE faults constituting a graben trending across the main axis of the pool. Lomalta interpreted the 3-22-11-16 W4M (3-22 well) and 6-15-1-16 W4M (6-15 well) wells to be situated in the graben and defining the trend of the faults. Lomalta alleged that its proposed 15C-15 well was somewhat to the east of the faults and maintained that its proposed well would penetrate the A Pool in a stratigraphically thickened part of the pool.

3.2 Views of Murphy

Murphy agreed with most of Lomalta's interpretation of the configuration of the A pool. However, believed that the 6-15 well is in a separate fault system and that the faults trend a few degrees further to the northwest-southeast than proposed by Lomalta. Murphy contended that the eastern edge of the fault may be closer to the applicant's 15C-15 well than anticipated by Lomalta. Murphy concurred however with the applicant that the proposed 15C-15 well, if drilled, would be situated in the A Pool.

3.3 Views of Texaco

Texaco stated that it believes the C Pool extends from its land in the NW 1/4 of section 15 to the NE 1/4 of section 15. Texaco alleged the Moulton Sandstone in township 1, range 16 W4M has been cut by two easterly trending faults with the wells 3-22-1-16 W4M and 13-14-1-16 W4M being interpreted to be in the down faulted zone. Texaco contended that Lomalta's proposed 15C-15 well would terminate in the C Pool and would result in unfair drainage of Texaco's adjoining C Pool acreage because of the close proximity to Texaco's contiguous lease.

3.4 Views of the Board

The Board generally agrees with the geological configuration of the A pool as presented by the applicant and by Murphy. The Board further agrees

with all parties that the Moulton Sandstone is geologically complex. However, the Board is of the view that there is insufficient geological evidence to support the existence of the east-west fault system as interpreted by Texaco. The Board believes Lomalta's 15C-15 well would penetrate the A Pool which is separated from Texaco's C Pool production by the NNW-SSW trending fault. The Board's interpretation of the pool configurations, along with those of the participants in the hearing is illustrated in Figure 2.

Texaco's intervention is based on its view that the applied for well would be in the C pool and thus result in unfair drainage to Texaco. Since the Board does not agree with Texaco's view on pool configuration, it considers that Texaco's opposition to the application does not have relevance, and consequently will not deal with it in the remainder of this report.

4 REDUCTION IN DSU SIZE

4.1 Views of Lomalta

Lomalta stated in its submission that a well in Lsd 15 was required to recover the oil that was proven to exist by the presently suspended well in Lsd 15.

4.2 Views of Murphy

Murphy stated that it had no objection to the establishment of one legal subdivision DSU's with a central target area, because it would provide for a more uniform spacing throughout the pool.

4.3 Views of the Board

Having regard for its conclusion that the area of application is indeed part of the Coutts Moulton A Pool, the Board believes that the requested reduction is justified because this DSU size is already in effect in most of the pool.

5 SHIFT IN TARGET AREA

5.1 Views of Lomalta

Lomalta is its submission and testimony claimed that the shift in target area was necessary for the following reasons:

- o The northwest quadrant of the legal subdivision is the target area in accordance with Board Order No. SU 800 in effect in the general area,

- o The proposed well would encounter an increased pay thickness of superior reservoir quality, and

- o The proposed well would produce oil not available for recovery from existing wells.

Lomalta qualified its position further by describing what it believed would occur for 2 cases, first, if Murphy's waterflood was effective, and secondly, if it was not. If effective, the proposed well would recover unswept oil south of the 2-22 well and along the edge of the graben. If the flood is not effective, the well would still be necessary in the proposed location to ensure recovery of as much as possible of the available hydrocarbons south of the existing wells, through a well with better porosity and permeability. Lomalta stated that moving northwest towards the graben was a risk worth taking to gain better reservoir quality and hence better productivity.

Lomalta considered that the shift in target area would not have an effect on equity because the wells in Lsd 1 and 2 of section 22 were located in the northern half of the legal subdivision and therefore a reasonable interwell distance would be maintained.

5.2 Views of Murphy

Murphy submitted that the proposed target area, and the well in the extreme corner of it, would result in unfair drainage. Murphy claimed that of the estimated 27 000 bbls (4300 m^3) recoverable oil from an average well in the Moulton A pool, 2/3 would be taken from Murphy's 2-22 drainage area and 1/3 would be produced from the area in Lsd 15 of section 15. Murphy also stated that it did not see a significant advantage to the shift in terms of conservation because essentially all of the oil would be recovered in any case.

5.3 Views of the Board

The Board notes that the requested target area in the northwest quarter of the legal subdivision is in accordance with Board Order No. SU 800. However, throughout pools in southeastern Alberta, where wells were already drilled on a centralized target area, these target areas were often maintained to secure a uniform drainage area per well. Therefore, the Board would not make the change automatically and believes that the requested change should be considered on the basis of conservation and of equity. As far as conservation is concerned, the Board does not agree with the applicant that the proposed well would produce oil not recoverable by the well in 2-22 and a well drilled in Lsd 15 of section 15 on the centralized target area for 1 Lsd spacing.

As far as equity is concerned, the Board notes that a shift in the target area would allow a well extremely close to lands owned by others and producing from the same pool. The Board believes this would likely result in inequitable drainage and since such inequities would not be offset by significant conservation gains, the Board is not prepared to approve the applied-for target area.

6 THE SUITABILIBTY OF THE PROPOSED 15C-15 WELL

6.1 Views of the Board

As noted in section 5 of this report, the Board is not prepared to approve a target area shifted to the northwest corner as requested by Lomalta. Consequently, if a well is drilled and completed as proposed by the applicant it will be subject to an off-target penalty factor. The Board's usual procedure is to not reduce an oil well allowable to less than the minimum allowance through the application of off-target penalty factors. However, if an oil well is located signficantly off-target to the extent that correlative rights are adversely affected, the Board may, upon the request of an offset owner and after considering the views of the off-target well owner, assign a penalized allowable less than the minimum allowance. The Board would be prepared to grant the well licence applied for by Lomalta but draws the above matters related to penalty factors to its attention.

7 DECISION

The Board approves the establishment of one legal subdivision DSU's with the target area in accordance with section 4.020 (2) of the Oil and Gas Conservation Regulations. The Board is prepared to approve Application No. 820218, but if the well is drilled and productive, the off-target penalty could be applied to the extent that its production rate would be less than the minimum allowance.

DATED at Calgary, Alberta on 28 May 1982.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

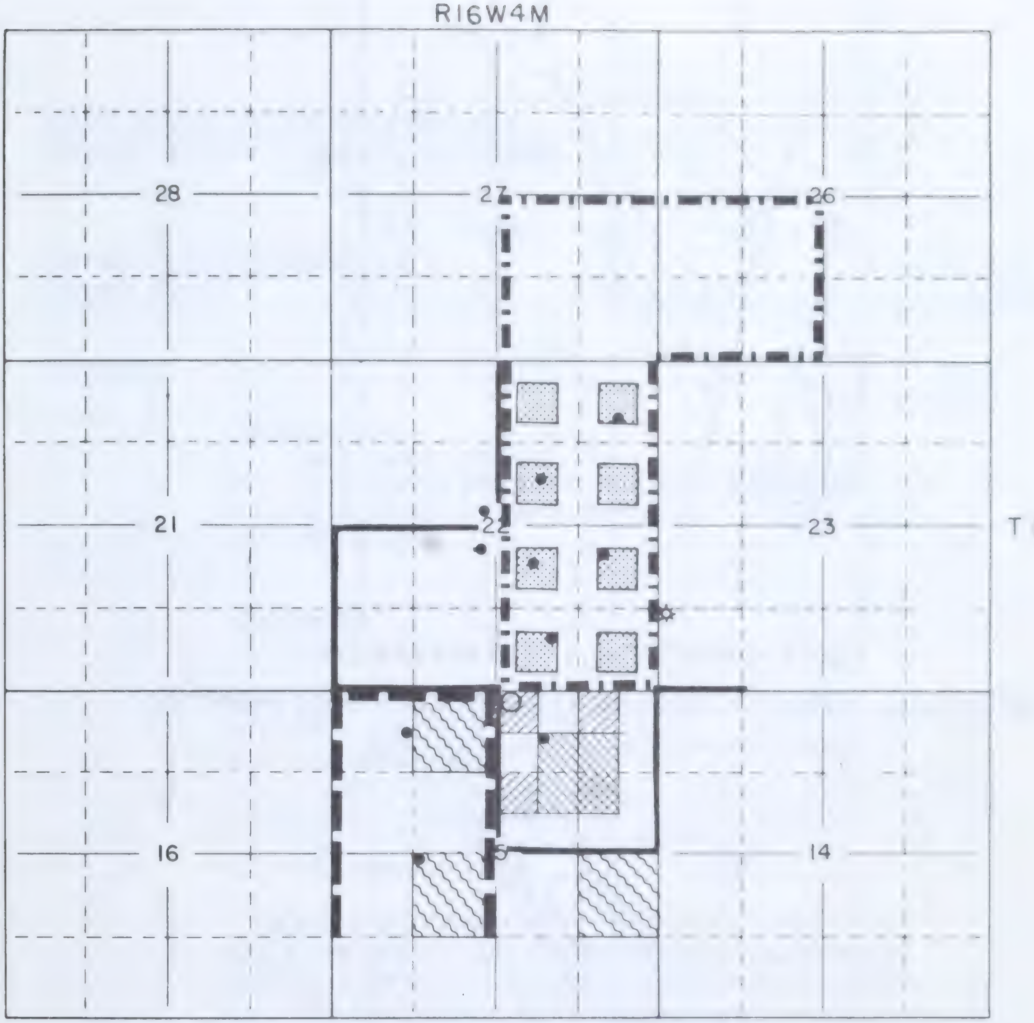
G. J. DeSorcy, P.Eng.
Vice Chairman

V E Bohme

V. E. Bohme, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member



COUTTS FIELD

SU 800 16ha Target Areas Applied for by LOMALTA

16ha Central Target Areas

LOMALTA 15C-15 Proposed Location

Moulton Oil Well

SU 800 64ha Target Area

Existing 64 ha Target Area

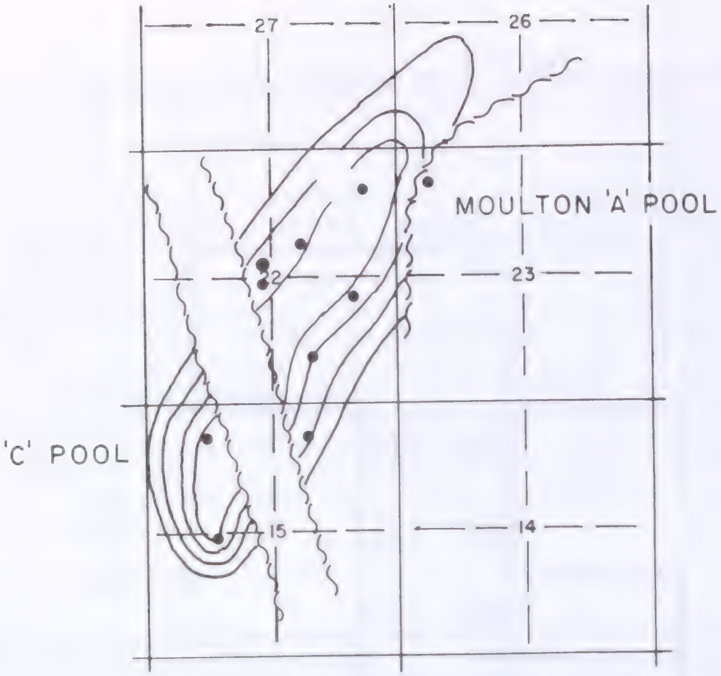
Coutts Moulton A Unit No. 1

Coutts Moulton A Pool

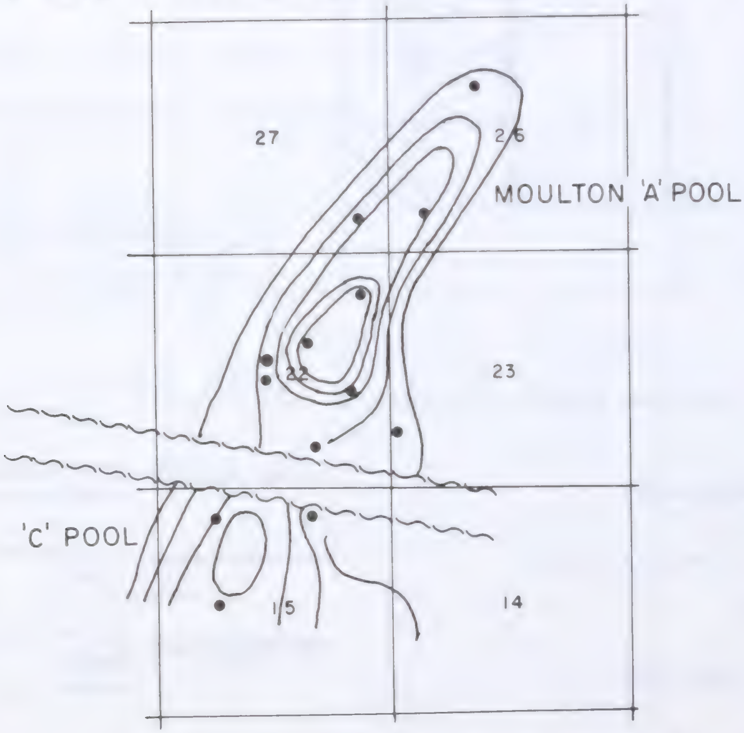
Coutts Moulton C Pool

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA CANADA

FIGURE 1



FAULT DIRECTION INTERPRETATION
AND POOL SEPARATION BY BOARD, LOMALTA AND MURPHY



FAULT DIRECTION INTERPRETATION
AND POOL SEPARATION BY TEXACO

FIGURE 2

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

MITCHELL ENERGY CORPORATION | Decision 82-19
OKOTOKS AREA | Applications 820260 and 820261

CONTENTS | Page

1 INTRODUCTION

1.1 Application 820260

Mitchell Energy Corporation (Mitchell) applied pursuant to the Oil and Gas Conservation Act, to reinstate well licence 92961 for a well, MEC OKOTOKS 11-30-20-28, to be drilled in legal subdivision 11 of section 30, township 20, range 28, west of the 4th meridian (Lsd 11-30-20-28 W4M). Mitchell also submitted three alternative well licence applications for Lsds 10, 15, and 4 of section 30 as shown in the figure. The purpose of the well would be to obtain sour natural gas production from the Crossfield Member of the Wabamun Group.

1.2 Application 820261

Mitchell applied, pursuant to the Pipeline Act for permits to construct pipelines associated with the three alternative well licence applications in the alternative to pipelines conditionally approved in ERCB Decision 80-4[1]. Those pipeline applications are described as follows:

(a) three alternative 88.9 millimetre (mm) outside diameter (O.D.) pipelines to transport sour natural gas from the alternative well locations to tie-in points in the NE1/4 30-20-28 W4M as shown in the figure, and

(b) three alternative 60.3 mm O.D. or 33.4 mm O.D. fuel gas pipelines for the three alternative well locations.

1.3 Background to the Applications

On 13 November 1979, the Energy Resources Conservation Board (Board) held a public hearing of Mitchell's applications for approvals to drill a well, and construct pipelines within section 30-20-28 W4M. The Board issued Decision 80-4 wherein it conditionally approved the applications. On 27 October 1981, well licence 92961 was issued for the well, MEC OKOTOKS 11-30-20-28.

On 18 December 1981, the Board received correspondence advising that Mr. D. deVries had not received notice of the 13 November 1979 hearing and that as an adjacent property owner he could be directly or adversely affected by the issuance of the well licence and requesting an opportunity to make submissions to the Board. The Board decided to hold

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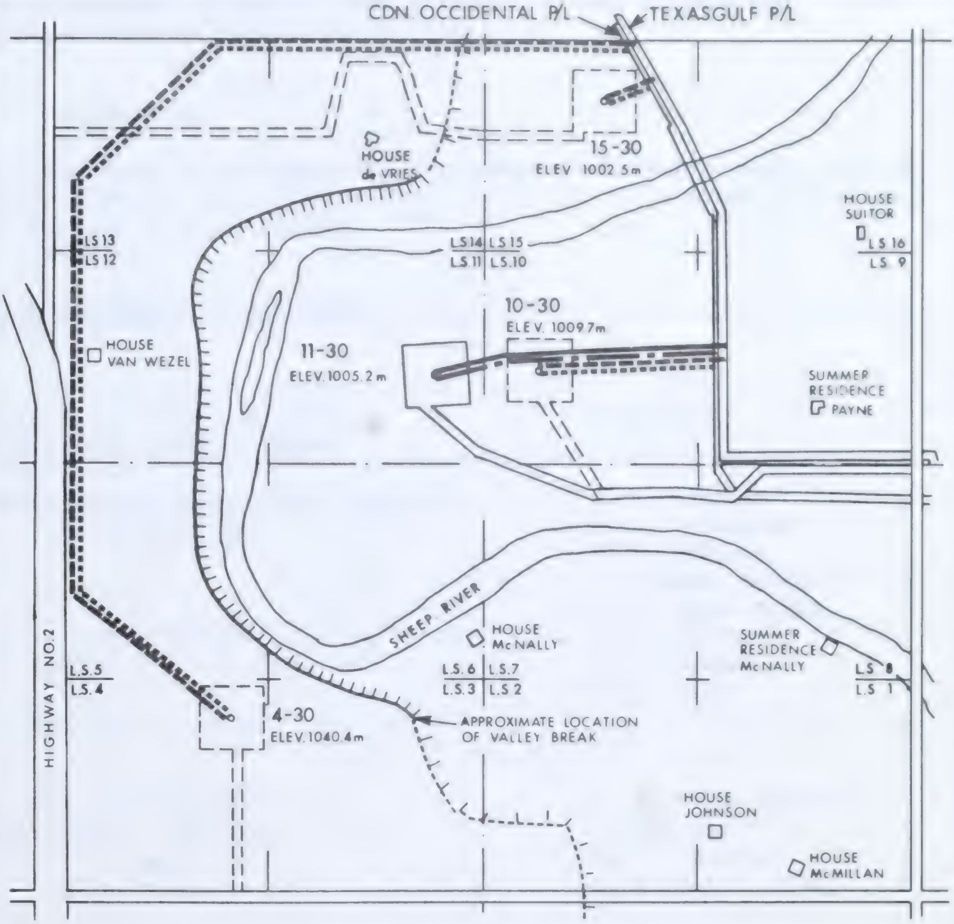
1 Energy Resources Conservation Board, 1980. Mitchell Energy Corporation Licence to Drill a Well and Permits to Construct Two Pipelines in the Okotoks Area. ERCB Decision 80-4. Calgary, Alberta.



MITCHELL ENERGY CORPORATION
SEC.30 TWP.20 RGE.28 W.4M.

Approved well site and access road - Decision 80-4
Approved sour gas pipeline - Decision 80-4
Approved fuel gas pipeline - Decision 80-4
Alternative well sites and access roads proposed by Mitchell
Alternative sour gas pipeline proposed by Mitchell
Alternative fuel gas pipeline proposed by Mitchell

a new hearing and suspended well licence 92961 on 20 January 1982. On 12 March 1982, Mitchell applied for the reinstatement of well licence 92961 or approval of one of three alternative well licence and associated pipeline permit applications.

1.4 The Hearing

A public hearing of the application was held on 27 and 28 April 1982, in Calgary, Alberta, with G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and L. A. Bellows, P.Eng., sitting.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Mitchell Energy Corporation (Mitchell) R. M. Wilkinson	B. W. Fischer M. L. Henkelman H. K. Milhoan R. Russel, P.Eng. A. C. Shea, P.Eng. A. E. Smith P. L. Tromp B. H. Wert
L. H. Payne (Mr. Payne)[2] D. deVries (Mr. deVries) L. M. Sali D. B. Reesor	L. H. Payne, P.Geol. D. deVries Dr. D. Davison G. A. Smith, P.Eng.
Rio Frio Ranch Ltd. (Mr. McNally) E. E. McNally	E. E. McNally
O. Sallenbach (Mr. Sallenbach) O. Sallenbach	O. Sallenbach

2 Mr. Payne and Mr. deVries filed separate interventions and gave separate arguments, but were represented by the same counsel and sat on the same panel of witnesses.

THOSE WHO APPEARED AT THE HEARING (continued)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Energy Resources Conservation Board staff K. F. Miller W. G. Remmer, P.Eng. H. W. Knox, P.Eng. M. A. Francis G. D. Agnew	

The Town of Okotoks filed a submission but did not appear at the hearing.

2 THE ISSUES

The Board considers the issues to be:

- the need and justification for a well and its related pipelines to recover reserves under section 30-20-28 W4M, and
- the acceptability of the proposed well sites and associated pipelines in comparison to each other.

3 NEED AND JUSTIFICATION

3.1 The Applicant's Views

Mitchell stated that it had, since the 1979 hearing, obtained agreement with the remaining mineral owners of section 30-20-28 W4M effectively pooling all the reserves underlying the section. It indicated that a well is required in section 30 because of the drainage characteristics of the reservoir. Mitchell cited the Board's findings from Decision 80-4 regarding the need for the well and stated that a well in section 30 would encounter excellent pay thickness, in excess of 35 metres (m), and would be structurally higher than other successful wells in the pool. Mitchell estimated the underlying reserves to be approximately 396 x 10^6 cubic metres (m^3), of which some 70 x 10^6 m^3 of gas would remain unrecovered if a well were not drilled in section 30.

Mitchell stated that it is not being competitive in the reservoir because it is not producing its share of gas, either on a cumulative or on a monthly basis. It indicated that the reservoir pressure under

section 30 continues to decrease as a result of lease-line drainage, and stated that a well centrally located in the section would minimize the effects of such drainage and yet effect maximum recovery of the reserves.

Mitchell stated that the gas produced from section 30 could be processed and sold through existing agreements and that it was attempting to secure additional markets for its gas. It noted that Okotoks South Unit gas production would be sold to Cominco Ltd. while the gas production from the Okotoks Gas Unit would be sold to Canadian Western Natural Gas Company Limited. Mitchell explained that it has agreement with Canadian Occidental Petroleum Ltd. to transport the gas produced from section 30 through an existing pipeline to be processed at the Canterra Energy Ltd. (Canterra) gas plant at Okotoks.

Mitchell stated that its future development plans included the drilling of up to six more wells, but noted that continued development would partially rely on the success of the proposed section 30 well. It indicated a belief that ERCB Informational Letter IL 81-7[3] outlined a reasonable approach to development. Mitchell stated that additional wells are needed to delineate the pool, and maintained that this development should precede residential development.

Mitchell stated that the pipelines would be necessary in order to operate the proposed well and to transport the produced gas through the existing gathering system to the gas plant.

3.2 The Interveners' Views

3.2.1 O. Sallenbach

Mr. Sallenbach, owner of a parcel of land in the SE1/4 36-20-29 W4M, stated that he does not approve of any more sour gas wells or pipelines in the area because they would have negative impacts on the value of his property and on the possibility of subdivision of his property.

3.2.2 E. McNally

Mr. McNally, owner of a portion of the S1/2 30-20-28 W4M, commented that questioning conducted at the hearing seemed to indicate that the most economic drainage of section 30 could be accomplished by unitization of

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3 Energy Resources Conservation Board, 1981. Exploration For And Production of Sour Gas Reserves in the Calgary-Okotoks Region. ERCB Informational Letter IL 81-7. Calgary, Alberta.

the field and alternative well sites outside of section 30. He questioned the need for a well in section 30 based on the evidence given by others. Mr. McNally further stated that a well in section 30, regardless of its economic value, should not be allowed to pose a threat to his family nor himself, no matter how small the risk.

3.2.3 L. Payne and D. deVries

Mr. Payne, owner of land in section 30 bounded by the Sheep River, and Mr. deVries, owner of a portion of the N1/2 30-20-28 W4M, stated that sour gas development in the area should be restricted. Mr. Payne stated that he is not satisfied that there is any requirement for additional deliverability from the Okotoks Crossfield Pool at this time, and believes that more co-operation between the operators and participants in the various units is needed to produce the gas from areas like section 30. Mr. Smith, appearing on behalf of Mr. Payne and Mr. deVries, stated that if delineation drilling is necessary to accomplish the goals of IL 81-7 such drilling should take place at locations not having unique topographical features. Mr. Smith proposed that a solution might be to drill a well in section 30 simply to establish the existence of reserves, then abandon the well and join all the units together for production purposes. Mr. Smith argued that the inability of the operators in the field to get along in this fashion should not affect the development plans of the surface owners.

Mr. Smith stated that the recovery of the Okotoks Crossfield Pool reserves could be accelerated with the drilling of more wells but contended that the only way to minimize impacts to surface developments in the area would be to require that the recovery of these reserves take place only from existing wells. Although he had not undertaken any reservoir studies to determine the extended pool life resulting from not drilling additional wells, he estimated an extended pool life of 40 to 50 years.

Mr. Payne and Mr. deVries did not comment on the need for a pipeline if a well was drilled and completed.

3.3 The Board's Views

The Board is satisfied that Mitchell has the right to the reserves under section 30 and believes that those reserves will be subject to continued lease-line drainage unless a well is drilled in section 30 or other arrangements can be made with other operators in the area. It is satisfied that significant reserves would remain unrecovered if a well were not drilled and that the pool life would be extended considerably. This extended life would result in impacts to surface owners from the existing facilities for a longer period of time. The Board also notes that Mitchell has agreements to process and market the gas. For the above reasons, the Board sees justification for a well and pipeline in section 30 provided the impact on the land surface is not unacceptable.

Respecting the contention that greater co-operation is needed amongst operators in order to produce the gas in an efficient manner, the Board, as indicated in IL 81-7, generally supports that view. It is nevertheless satisfied that a well is required in the immediate vicinity of the central portion of section 30 to effect efficient drainage of the reserves. The need is even greater under the existing mode of competitive operations.

4 THE ACCEPTABILITY AND A COMPARISON OF THE PROPOSED ALTERNATIVES

4.1 The Applicant's Views

While commenting on the advantages and disadvantages of its applied-for alternatives, Mitchell stated that to bring on stream the 11-30 or 10-30 alternatives would cost about $1.6 million (U.S.) with approximately $1.21 million (Canadian) of the total accounting for drilling costs. For the 4-30 and 15-30 alternatives, Mitchell stated that because at least one "whipstock"[4] would be required to ensure that the well entered the target area, these wells would cost approximately 10 per cent more than the 11-30 or 10-30 alternatives. It stated further that to directionally drill a well from those locations for optimum drainage would cost approximately 30-40 per cent more than a vertical hole. It emphasized that its evaluations were based on vertical hole cost estimates using simple percentage increases for deviated hole costs. Regarding pipeline costs, Mitchell noted that the 4-30 pipeline alternative would cost about $150,000 (Canadian) while the 15-30 pipeline alternative would cost approximately $20,000 (Canadian). Mitchell summarized its economic evaluations by stating that the 11-30 alternative would represent a fair yet marginal investment, and by indicating the following economic preferences in order: 10-30 or 11-30, 15-30, and 4-30.

Mitchell stated a significant reserve of gas would not be recovered if a well were not drilled in section 30. It indicated that the 10-30 and 11-30 alternatives would provide the best total reserve recovery for the section while the 4-30 and 15-30 alternatives would provide slightly less recovery. Mitchell cited possible drainage interference for the 15-30 alternative from a prolific well in 11-29-20-28 W4M, resulting in competition for the same reserves. For the 4-30 alternative, Mitchell indicated that potential water interference problems may occur down slope in the reservoir.

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4 A term describing a procedure used to alter the direction of the wellbore.

Mitchell noted that the reservoir pressure under section 30 has been reduced because of lease-line drainage and stated that the 15-30 alternative would reduce this drainage most effectively because it is closer to the existing producing wells. At this location, gas production would reduce the amount of gas flowing to the lower pressure areas of the reservoir. Mitchell stated that wells in 10-30 or 11-30 would also reduce lease-line drainage.

When questioned regarding the environmental impacts of the alternatives, Mitchell inferred that aesthetic impacts were the major concern of the landowners in the area and that a "small well site would be not totally demeaning". It suggested little difference between the alternatives but believed the 15-30, and then the 4-30 alternative, to be marginally better because they would not be as apparent from the Payne or deVries residences.

With respect to safety, Mitchell maintained that its planned procedures would minimize the possibility of a release of sour gas. It stated that H_2S detectors, pit totalizers, and return drilling mud flow detectors would be used in addition to "class 4 BOP"[5] equipment. Mitchell also indicated that an H_2S scavenger drilling mud additive would be used while drilling into the Crossfield Member.
Mitchell advised that although the probability of a blowout during drilling would be remote because of low formation permeability and also reduced reservoir pressure, it would be using an emergency response plan "commonly used in (this) area now by all the operators". It stated that five safety personnel would be on site while drilling into the Crossfield Member (for approximately 1 week) and that they would be responsible for monitoring the public usage of the Sheep River in addition to their regular safety duties. Mitchell stated that signs noting the possible occurrence of sour gas would be erected near the river during the drilling of the well. It also undertook to conduct an H_2S "safety" education program and an emergency simulation for the area residents prior to drilling into the Crossfield Member.

During the interim between completion and production of the well, Mitchell stated it would lock both master valves and fill the production tubing with an inhibited fluid. It said that the 3-4 week construction period for the production facilities would begin immediately after drilling and completion of the well.

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5 Blowout prevention equipment requirements are detailed in the Oil and Gas Conservation Regulations.

Mitchell stated that once the well was on production, the field operator, Canterra, would be inspecting the well site daily. It said that Canterra's Emergency Contingency Plan includes procedures for the contact of residents, evacuation if needed, and the ignition of a significant gas release, should one occur. While Mitchell had not undertaken any studies to determine the times available for evacuation, it estimated that up to one hour might be available depending on the nature of a release. It stated that the pipeline gas temperature and pressure, as well as H_2S concentrations at the well site, would be remotely monitored by the Canterra control centre and that Canterra would be able to remotely close the fail-safe surface safety valve if H_2S was sensed by the H_2S detectors. Mitchell stated that such occurrences would be immediately investigated by Canterra field staff.

Mitchell stated that a fail-safe down hole safety valve (DHSV) would be installed on the well to minimize any gas release. Additionally, a production packer would be set above the Crossfield Member and the well-bore annulus would be filled with inhibited fluid in accordance with the Oil and Gas Conservation Regulations.

In its application, Mitchell stated that a well drilled in section 30 would probably be a level 2 sour gas facility, as detailed in ERCB Interim Directive ID 81-3[6] and that the associated pipelines would be classified as level 1 facilities with the exception of the 4-30 pipeline. Approximately 1.25 kilometres (km) of the 4-30 pipeline would be classified as a level 2 facility.

Mitchell noted that the 10-30, 11-30, and 15-30 alternatives were located in a semicircular "bowl" (see figure) at lower elevations than the 4-30 alternative. When questioned whether or not the 4-30 alternative would perhaps be a better location than its preferred 11-30 alternative, having regard for a potential gas release, Mitchell stated that H_2S is heavier than air and could, in the unlikely event of a well blowout or pipeline rupture, simply flow to the edge of the bowl and gravitate downward. It suggested that locating the well in 4-30 would simply transpose the effects. Mitchell also noted the proximity of the 4-30 well site and pipeline to Highway 2 and a country residential subdivision immediately west of Highway 2. It suggested that the risk associated with the 4-30 alternative might be greater than the "bowl" locations because of the increased number of people that could be affected.

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6 Energy Resources Conservation Board, 1981. Minumum Distance Requirements Separating New Sour Gas Facilities From Residential and Other Developments. ERCB Interim Directive ID 81-3. Calgary, Alberta.

Regarding the risks associated with a gas release from a location such as 10-30 or 11-30, Mitchell maintained that a well in that "location doesn't present any particular hazard more than it would in another location". It stated that the probability of gas release from a directionally drilled hole was the same as from a vertical hole. Mitchell pointed out that the 10-30 alternative was essentially equidistant from the Payne, McNally, and deVries residences, at a much greater distance than the minimum stipulated by ID 81-3. In its opinion, all of the alternatives meet the separation distance requirements.

With respect to the safety associated with the alternative pipeline routes, Mitchell stated that the 4-30 pipeline would be the most undesirable because it would be the longest (2.25 km), parallel to Highway 2, in close proximity to the Van Wezel residence, and would require an above-ground emergency shut down (ESD) valve assembly to minimize any potential release. Mitchell stated that it had considered more direct pipeline routes from the 4-30 well site to the existing Canadian Occidental pipeline or the Canterra gas plant, but believed that the respective environmental impacts and increased lengths, risks, and costs were unacceptable. From a safety point of view, Mitchell saw little difference between the remaining pipeline alternatives, but ranked them on a length basis, that is, 15-30 (shortest), 10-30, 11-30, and finally 4-30 (longest). In summary, Mitchell contended that the 11-30 and 10-30 alternatives would be safer than the 4-30 alternative and that the 15-30 option was similar to the 11-30 and 10-30 alternatives. It stated that the 4-30 alternative was its last choice mainly because of the pipeline route.

Mitchell stated that its evaluation of the alternatives having regard for economics, recovery of reserves, lease-line drainage, environmental impacts, and safety resulted in the following order of preference: 11-30, 10-30, 15-30, and 4-30.

4.2 The Interveners' Views

4.2.1 O. Sallenbach

Mr. Sallenbach stated that he is opposed to further sour gas development in the area because such further development would restrict the usage and development potential for his land, in addition to devaluating the property.

4.2.2 E. McNally

Mr. McNally stated that the 4-30 alternative directly affected his property. He indicated several impacts to it from the 4-30 alternative including that the well would be located on a commercial deposit of sand

and the well site and access road would seriously impact his farming operations.

Mr. McNally suggested an alternative location to the south and east of the proposed 4-30 location indicating that his residence would then be in less danger and it would be more convenient to farm the land. He stated that there may be greater risks to his residence from the 10-30 and 11-30 sites in comparison to the 4-30 site and that the 15-30 alternative would have the least effect to him as it was the farthest away.

Mr. McNally indicated his order of preference to be the 15-30 site, the 4-30 site conveniently located, and lastly, the 11-30 and 10-30 sites.

4.2.3 L. Payne and D. deVries

Dr. Davison, appearing for Mr. Payne and Mr. deVries, indicated that unique meteorological conditions may exist over section 30 because of the complexity of the terrain in the area. He stated that the meteorological conditions could, in the event of a well blow out or pipeline rupture, seriously affect the safety of individuals located in the bowl, particularly if the 11-30 or 10-30 alternatives were approved. He explained that two situations dependent on the atmospheric stability conditions, windspeed, and wind direction, could result in poor dispersion characteristics in the bowl for approximately 50 per cent of the time.

The first such condition involves "eddies" or circulation cells formed as the wind passes over the steep valley wall immediately west of the 11-30 site. These would occur in neutral stability conditions according to Dr. Davison, but he was uncertain as to the downwind extent of these eddies. He postulated that they could extend to Mr. Payne's summer residence.

The entire valley flow "decoupling" from the flow above the valley was the second situation cited by Dr. Davison. He stated that this condition occurs in stable atmospheric conditions "virtually every night". He indicated that air movements or circulation within the valley under these situations would be limited to "weak flows", effectively creating a stagnation area. Furthermore, he stated that in the event of a well blowout, pipeline rupture, or leak, potentially dangerous concentrations of sour gas could slowly migrate or remain localized within the valley, possibly affecting the residents.

Dr. Davison stated that a blowout or pipeline rupture with the wind blowing directly towards the McNally residence from a well site in the bowl would represent the worst case situation from a safety point of view. He recognized, however, that lethal concentrations would likely

not affect the McNally residence if Mitchell's proposed safety devices limited the amount of gas that could be released.

Dr. Davison stated that, in his view, the concepts of ID 81-3 were applicable for evaluation of the 4-30 alternative since it was on relatively level land, but they were not applicable to the proposed sites in the "bowl". When considering safety aspects and having regard for the special meteorological conditions and potential consequences for each of the well site and pipeline alternatives, he ranked the alternatives in order of preference as 4-30, 15-30, 10-30, and 11-30.

Mr. Smith also expressed concerns for potential fatalities in the valley as a result of a release of H_2S gas. The release, he explained, might occur as a result of a well blowout or a leak from a flanged connection or a corrosion pinhole. He stated that he was more concerned with a leak occurring during the production stage of the well and suggested that the probability is high of having "an accumulation of gas in (the) valley that could result in someone being killed".

Mr. Smith cited several examples of gas leaks occurring in the area in the past, and stated that leakage rates may not be sufficient to activate the well or pipeline safety devices. He suggested that a well in the bowl might be acceptable if there were no residents located there or, alternatively, the well should be drilled at the highest elevation possible.

To summarize his personal position, Mr. deVries stated that the 15-30 alternative and the 4-30 alternative pipeline would have direct impact on his lands in the N1/2 30-20-29 W4M. He indicated that the 15-30 site was underlain with economic gravel deposits. Mr. deVries contended that the 4-30 alternative was the best, but only if an alternative pipeline route, such as directly west to the Canterra gas plant, was chosen. However, he stated that if the proposed pipeline from the 4-30 site had to cross his land he would then prefer the 15-30 alternative. He noted in his intervention that the 10-30 and 11-30 alteratives would, in his opinion, create unacceptable risks in the event of an H_2S gas release because of the unique topography of the area.

Mr. Payne suggested that Mitchell's 10-30 and 11-30 alternatives warranted special consideration because of the topography and unique meteorological conditions in the bowl. He believed that the residents in the valley would be in danger from a well in the bowl and that recreational use of the river would probably have to be curtailed for safety reasons. In Mr. Payne's opinion, the 4-30 alternative, with an alternative pipeline route, was the most acceptable because the well site would be located on high ground. He ranked the alternatives in order of preference as 4-30, 15-30, 11-30, and 10-30.

4.3 The Board's Views

The Board compared economics, conservation of reserves, reservoir equity, land use, and safety and technical considerations, to determine the relative acceptability of the four alternatives.

Economic Considerations

The Board accepts Mitchell's total development cost estimate of $1.6 million (U.S.) for the 10-30 or 11-30 alternatives. It also accepts Mitchell's vertical-hole drilling cost estimates but believes the 10 per cent incremental cost increase to directionally drill the 15-30 or 4-30 alternatives might be low having regard for the economic risks associated with directional drilling. The Board also accepts Mitchell's pipeline cost estimates. Review of the evidence indicates that the 10-30 and the 11-30 well and pipeline alternatives would have modest cost advantages in comparison to the 15-30 and 4-30 alternatives.

Conservation of Reserves

The Board believes that effective recovery of the reserves under section 30 is a significant consideration. The Board concurs that a well centrally located in section 30 would result in the best recovery of the reserves underlying the section but its review of the probable drainage areas offered by the 15-30 and 4-30 alternatives indicates that, depending on what other wells might be drilled in the general area, the majority of the reserves would also be recovered with those alternatives. Therefore, the Board sees little difference in the alternatives when considering the recovery of reserves.

Reservoir Equity

With respect to equity, the Board notes the reduction of reservoir pressure under section 30 and is of the opinion that the general direction of gas flow in the reservoir is northward toward a pressure sink created by the existing producing wells. There are also localized drainage situations. The Board is of the view that the 4-30 alternative would be least effective in minimizing lease-line drainage because it is farthest from the existing producing wells. Conversely, the 15-30 alternative would be closer to the existing wells and could be most effective in combating lease-line drainage. Withdrawal points in 10-30 or 11-30 would also assist in this respect. The Board sees a modest disadvantage to the 4-30 site with respect to lease-line drainage, but little difference otherwise.

Land Use

In evaluating impact on land use the Board considered whether the construction of a new access road to any of the alternatives was necessary as well as the impact of the alternative well sites and

pipelines. Regarding the current land use, the Board notes that all of the lands are being used for agricultural or recreational purposes. It believes that the future land use in the area would be similar to the current land use but accepts that the landowners potentially affected may undertake sand or gravel extraction developments in the future, since such deposits apparently underlay each of the sites. As far as land use impact of the well itself is concerned, the Board sees little difference between the alternatives because the land use and the well site size are essentially the same for all the alternatives.

Having regard for only the access road, the Board views the 15-30 alternative to be superior to the remaining alternatives because it requires only maintenance of an existing road as opposed to the construction of a new access road.

The Board is of the opinion that the impact of a pipeline on land use is proportional to the length of the pipeline and therefore the 15-30 alternative would have the least impact. Similarly, because the 4-30 pipeline entails approximately 2.25 km of line, the Board believes it would have the most impact. The 10-30 and 11-30 alternatives would have marginally more impact than the 15-30 alternative.

The Board concludes, having regard for the land-use considerations evaluated, that the 15-30 alternative is superior to the remaining alternatives. While it considers all of the alternatives acceptable it is of the opinion that the impact of the 4-30 pipeline would be significant.

Safety and Technical Considerations

The safety and technical considerations reviewed for each of the alternatives included the potential H_2S release rate from the well, the length of sour gas pipeline, the proximity to residents, transients, and major roads, dispersion characteristics of the alternative locations, and emergency procedures and design features.

The Board considers the potential H_2S release rate from any well in section 30 to be an important factor in evaluating the potential risk. The Board accepts Mitchell's statements regarding the flow capabilities from a well drilled into the Crossfield Member prior to and after stimulation. With respect to the production stage of the well, the Board notes Mitchell's proposal to install a down-hole safety valve and believes any volume of gas released from the well would be limited by the valve. The Board considers the four alternatives to be essentially the same with respect to the potential release volumes or flow rates.

The Board is of the opinion that the safety of a sour gas pipeline is related to its potential H_2S release volume (a function of pipeline length between isolating valves) and therefore concludes that the 4-30 pipeline would present the most risk. Conversely, the 15-30, 10-30, and

11-30 pipelines would have minimal risk associated with them because of their short lengths and related small potential H_2S release volumes.

Regarding the proximity of the alternative sites to residences, transients, and major roads the Board considered the proposed well sites and pipelines separately. Review of the evidence indicates that for each of the well site alternatives a permanent residence would be located approximately 425-500 m away. Consequently, the Board sees little difference between the alternatives, having regard for proximity to permanent residences. With respect to recreational users of the Sheep River, the Board sees essentially no difference in the well site alternatives located within the valley. However, it considers the proximity of Highway 2 to the 4-30 well site to be a significant factor because of the high traffic volumes.

With the exception of the 4-30 pipeline, which would be in close proximity to the Van Wezel residence, the Board notes that the proposed pipeline alternatives are at least 195 m from all residences. With respect to the 4-30 alternative the Board notes that it is located on flat terrain above the valley. However, it also recognizes that the remaining pipeline alternatives are significantly shorter and are farther from residences. The Board also believes the 4-30 pipeline alternative could have the most impact to transients because it would parallel Highway 2. The Board therefore concludes that while all the alternatives are acceptable in terms of their proximity to residences, transients, and major roads, the 4-30 alternative would have more disadvantages associated with it.

The Board recognizes the interveners' concerns regarding dispersion characteristics resulting from the unique topography of the area and consequently it has evaluated the factors it views as important when considering the probable dispersion characteristics for the four alternative locations. The factors considered were proximity of a proposed well site to the valley break (see figure), and whether a "circulation cell" is possible. The Board then compared the risk from a potential H_2S release considering the above factors.

For the alternatives located in the valley, the Board believes that the proximity of a well site to the valley break is important in relation to the probability of formation of lee eddies as described by Dr. Davison. The Board is of the opinion that stagnant circulation cells or lee eddies may occur for the 10-30, 11-30, and 15-30 alternatives, but that they would not occur for the 15-30 site as often or with the intensity of those for the 10-30 or 11-30 sites. The Board agrees with Dr. Davison's assessment that those meteorological conditions would not occur with the 4-30 well site. However, the Board believes that in the event of a leak it would be possible for H_2S to gather and flow into the valley from the 4-30 alternative.

In comparing the risk associated with a potential H_2S release, the Board is satisfied that the 10-30 and 11-30 alternatives would have the most risk associated with them because of the meteorological conditions in the valley. The Board considers that the 15-30 site would have less risk and that the 4-30 alternative would have the least risk associated with it. The Board considers this matter of the dispersion characteristics to be a significant factor in assessing the safety of the proposals.

The Board has reviewed the emergency procedures and design features proposed by Mitchell for the drilling and production stages of a well in section 30. It is satisfied that the well site would be adequately monitored throughout the drilling and subsequent production life of the well. The Board also reviewed the proposed well and pipeline design and safety features proposed by Mitchell and believes them to conform to the appropriate design standards and regulations. It is also of the opinion that the emergency simulation proposed by Mitchell would help determine the effectiveness of the emergency contingency plan. With regard to this plan, the Board reviewed the possible evacuation routes for the residents in the event of an H_2S release and is satisfied that they are all essentially away from the proposed well sites, with the exception of the route available to Mr. McNally in the event of an H_2S release from the 4-30 alternative.

The Board concludes that with respect to emergency procedures and design features, that the 11-30, 10-30, and 15-30 sites have advantages over the 4-30 proposal because it would require special procedures due to the lack of an appropriate evacuation route.

Summary

In conclusion, the Board sees little difference between the alternatives having regard for economics and conservation of reserves. With respect to equity and land-use considerations it considers the 15-30 alternative to have certain modest advantages over the other alternatives. Considering safety and technical considerations, the Board believes that the 10-30 and 11-30 alternatives have the most risk associated with them. While it considers these risks not to be unacceptable, its sees the 15-30 and 4-30 alternatives as having certain advantages. However, the major advantage of the 4-30 alternative, the best dispersion characteristics, does not balance the numerous disadvantages of that alternative, including its proximity to Highway 2 and the length of the required pipeline. Consequently, although the Board does not see a major difference in the sites, it considers the 15-30 alternative to be the best of those considered.

5 DECISION

The Board is prepared to approve the Mitchell Energy Corporation Limited applications for a licence to drill a well at Lsd 15-30-20-28 W4M and for permits to construct the necessary related pipelines. The Board

notes that the 15-30 proposal involves a directionally drilled well. It is not certain that the directional drilling is essential in terms of conservation or lease-line drainage, or of target area requirements. The latter aspect of this conclusion has regard for the ownership of mineral rights in the area and the liklihood that the target area may be changed.

Consequently, the Board would expect that Mitchell may wish to investigate the possible drilling of a vertical hole from the proposed site in 15-30.

DATED at Calgary, Alberta, on 19 July 1982.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

L. A. Bellows

L. A. Bellows, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

PEMBINA PIPE LINE LTD.
APPLICATION FOR WATERFLOOD
CONCURRENT PRODUCTION APPROVAL REVIEW
MEDICINE RIVER OSTRACOD A POOL

Decision 82-20
Application No. 810982

1 INTRODUCTION

1.1 The Application

Pembina Pipe Line Ltd. applied pursuant to section 38 of the Oil and Gas Conservation Act (now section 26 of the Revised Statutes 1980), for approval of a scheme for enhanced recovery of oil by water injection in the part of the Medicine River Ostracod A Pool (A Pool) shown in Figure 1. In addition, the Board considered the matter of concurrent production as approved under the terms of Board Order No. Misc. 7717 and its effect on the various modes of reservoir depletion presented in the application.

1.2 Background

This scheme would be the second waterflood scheme in the A Pool. In 1971 a waterflood scheme was initiated for Project 1 area shown on Figure 1. In January 1977 Chevron Standard Limited applied for approval of concurrent production of the oil zone and its associated gas cap in the then defined Medicine River Ostracod M Pool (M Pool), and commingling of gas production from the Medicine River Glauconitic D Pool and the M Pool in the well BA CPR Murto Sylake 10-17MU-39-2. At that time the M Pool consisted of only one producing gas cap well and one producing oil well. The Board approved the application on the condition that the oil zone be placed on continuous production with no restriction on the oil production rates and Board Order No. Misc. 7717 and MU 180 were issued for those purposes.

Effective October 1 1979 the Ostracod V Pool and Section 12-39-3 W5M were coalesced into the M Pool and total gas production from the M Pool was restricted to 110×10^3 m^3 per day. At that time operators in the Medicine River Field were requested to assess the possibility of communication between the M Pool and the A Pool to the west.

In Informational Letter IL 81-19 entitled "Gas Rate Limitation, Concurrent Production and Pool Definition - Medicine River Ostracod A and Ostracod M Pools", the Board pointed out that the gas rate restriction of $110 \times 10^3 m^3$ per day had been severely exceeded during the previous 16 months and furthermore, studies that were to be submitted by April 1981 had not been

received. The Board stipulated that unless the studies were received by September 1, 1981, it would initiate proceedings to shut in the pool.

By letter dated 20 August 1981 Pembina Pipe Line Ltd. submitted a report on the first two phases of a three-phase reservoir engineering study being carried out on the M Pool. The report contained a reservoir description and an analysis of pressure and production data which indicate reservoir communication between the A and M Pools. The report further indicated that operators of the M Pool were prepared to divide the restricted gas production of 110 x 10^3m^3 per day equally among wells in the pool on a well count basis. Phase III, concerning the feasibility of waterflooding the M Pool, was submitted under letter dated 3 December 1981. The combined studies were included with Application No. 810982, the subject of this proceeding.

The Board issued Informational Letter IL 81-31 on 17 December 1981 entitled "Pool Coalescence, Good Production Practice and Concurrent Production - Medicine River Ostracod A and Ostracod M Pools". By direction of the letter, the A and M Pools were coalesced on 1 January 1982, and good production practice status for the oil zone was removed from the previously defined M Pool. Intentions were expressed in the letters to hold a public hearing as early as practicable in 1982 for the purpose of considering the proposed waterflood scheme and the impact of concurrent depletion on the subsisting and proposed waterflood operations.

1.3 The Hearing

A public hearing of the application was held on 10 and 11 March 1982 with G. J. DeSorcy, P.Eng., N. Strom P.Eng., and J. R. Pow, P.Eng., Acting Board Member, sitting. Due to several requests for additional information, the hearing was adjourned and re-convened on 19 and 20 April 1982. At that time the applicant filed an amended application. The following table lists the appearances at the hearing.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Pembina Pipe Line Ltd. (Pembina) W. E. Martin, P.Eng.	W. E. Martin, P.Eng. M. N. Young, P.Eng. B. G. Kergan, P.Eng. of D & S Petroleum Consultants (1974) Ltd. (D & S) B. A. Slevinsky, P.Eng. of D & S
CDC Oil & Gas Limited (CDC) M. Azzam J. Wansleeben, P.Eng.	L. E. Fenwick, P.Eng.
Chevron Standard Limited (Chevron) R. A. Pashelka,	E. S. Bundgaard, P.Eng. R. A. Filgate, P.Eng.
Czar Resources Ltd. (Czar) D. J. Wandzura, P.Eng.	
Hudson's Bay Oil & Gas Company Limited (HBOG) M. B. Field, P.Eng.	M. B. Field, P.Eng. L. Havinga
Sabine Canada Ltd. (Sabine) D. P. Andrews, P.Eng.	A. L. Anderson, P.Eng. R. Douglas, P.Eng.
Energy Resources Conservation Board staff R. S. Holmes A. R. Olive R. J. Willard, P.Eng. C.J.C. Page	

2 POSITION OF THE APPLICANT

Pembina applied to inject water at three wells in Lsd 10-1-39-3 W5M (10-1), Lsd 2-11-39-3 W5M (2-11) and Lsd 4-14-39-3 W5M (4-14) in the A Pool (see Figure 1).

To support its application Pembina submitted a comprehensive model study and economic evaluation by D&S. Seven depletion options (outlined in Table I) were analyzed.

Pembina contended that the current depletion scheme (Case 1), in which the oil zone is produced in accordance with good production practice and the gas cap is produced concurrently at restricted rates, was very inefficient and would result in a loss in the recovery of oil that could otherwise be recovered by a suitable waterflood scheme. It further submitted that the recovery efficiency of the pool depends significantly on the curtailment of the pressure depletion and fluid migration losses caused by the continued production of the gas cap.

Pembina studied a number of combinations of water injection and gas cap production situations, and concluded that Case 3A shown on Table I, would be the optimum arrangement. It requested that this scheme of water injection and controlled gas cap withdrawals be approved by the Board. Under Case 3A the applicant requested approval of the following method of operations:

i) shut in the three gas cap wells in Lsd 13-8-39-2 W5M (13-8), Lsd 10-17-39-2 W5M (10-17) and Lsd 10-18-39-2 W5M, (10-18)

ii) initiate water injection at three injection wells (10-1, 2-11, and 4-14) to balance withdrawals from the oil zone,

iii) produce the gas cap through the transition wells located in Lsd 11-17-39-2 W5M (11-7) and Lsd 2-13-39-3 W5M (2-13) at a rate of 51 x $10^3 m^3$ per day,

iv) appropriately allocate the gas produced from 11-7 and 2-13 above a gas-oil ratio of 210 m^3/m^3 among the owners of these two transition wells and the three gas cap wells (13-8, 10-17 and 10-18)

Pembina submitted that as long as concurrent production is allowed to continue through production of the gas cap wells, there is no incentive for the gas cap owners to participate in any unit agreement. Further, the oil zone (Area 3) excluding Project No. 1, and the transition zone (Area 4) as shown in Figure 2 would have to be unitized to permit the mode of depletion proposed under case 3A.

In Case 4, the oil zone voidage would be replaced and the transition and gas cap wells allowed to produce at a restricted gas rate of 70 x $10^3 m^3/d$. Though oil recovery from this case is 12 x $10^3 m^3$ lower than Case 3A, the total present worth is $1.4 million more. Pembina referred to comparative calculations of present value for oil zone and gas cap regions (Table 2), and on this evidence argued that Case 4 does not reasonably preserve equity between areas of the pool; ie. it shifts the present worth in favour of the gas cap owners and reduces the present worth of the oil zone.

Although Pembina recommended that Case 3A be adopted as the optimum depletion mode, it submitted, as an acceptable alternative, Case 5 where four additional water injection wells would be drilled along the gas-oil contact to replace the gas cap voidage and thereby totally prevent the pressure depletion effects caused by gas cap withdrawals.

At the request of the Board the applicant evaluated a further situation with an additional injection well at Lsd 11-12-39-3 W5M (11-12) and gas production rates corresponding to Cases 3A (Case 6) and 4 (Case 7). The applicant noted that in Case 6 the oil recovery dropped from 275 x 10^3m^3 to 263 x 10^3m^3 even though oil migration into the transition zone was significantly reduced. Pembina submitted that the total present value of the pool increases in Cases 6 and 7 but the majority of the gain is realized by the gas cap owners. Pembina contended that it would be unreasonable to expect the oil owners to drill an up-dip injector that would lessen oil recovery and primarily benefit the gas cap owners.

As indicated on Table 1 the applicant evaluated several other cases, but did not consider them as advantageous when compared to the proposed alternatives.

3 POSITIONS OF THE INTERVENERS

CZAR

Czar, as operator of a gas cap well (10-18), submitted that concurrent production in the A Pool should continue. It stated that if only the oil zone was allowed to produce, gas cap depletion would occur through the transition wells, resulting in a loss of both reserves and cash flow to the gas cap owners. Czar did not attend the second session of the hearing and therefore was not available for cross-examination or comment on Pembina's sharing proposal with regard to coned gas cap reserves.

CDC

CDC, the operator of the 11-7 transition well, supported the applicant's position that waterflooding is desirable for optimum oil recovery. It noted, however, that the higher gas production rate under Case 4 would have a positive impact on both the total energy recovery rate and present value of the pool. It maintained that a unit or operating agreement between the gas cap and the oil zone owners would be necessary before either Case 3A or 4 is implemented. CDC also pointed out that the terms of unitization could be affected by the manner in which the Board might rule on the Pembina application.

SABINE

Sabine, as operator of the 2-13 transition well, agreed generally with the results of the model study and recommended that a waterflood operation be implemented as soon as practicable. Sabine contended that to avoid prejudicing unit negotiations, no scheme should be approved until all affected areas of the pool are unitized. It proposed allowing continued production under the current rules until 1 August 1982 when the Board should shut in the pool (with the exception of Project No. 1) if a unit or operating agreement were not in force. Sabine was concerned that, without such firm direction from the Board, a timely resolution of unit negotiations could not be achieved. Under cross-examination Sabine submitted that it may be possible for the owners of the oil and transition zones to form a unit if an agreement could be made to transfer payments to

the gas cap owners. However, such an agreement would be difficult to reach due to the problems inherent in satisfying both working interest and royalty owners.

Sabine viewed both Cases 3A and 4 as reasonably effective schemes but commented that additional modified cases may prove optimum and supported further study in this regard.

HBOG

HBOG, as operator of the existing waterflood project, expressed concern that concurrent production from the pool and continued primary depletion has established a pressure differential across the pool, resulting in the recent migration of oil from its Project No. 1 area and the creation of a substantial gas saturation in the oil zone. HBOG supported the application and viewed Case 3A as a reasonable compromise between the various interests.

HBOG recommended that water injection commence at the 10-1, 2-11 and 4-14 locations as soon as possible and at sufficient volumes to maintain a voidage replacement ratio of 1.5 until pressure parity is established with Project No. 1.

HBOG indicated a reluctance to use the well located in Lsd 10-22-39-3 W5M (10-22) as an injector in Project No. 1 at this time but said it would consider the move once response from the new waterflood scheme is observed.

In summary, HBOG requested the Board to set rules to effect the fair treatment of the various interests across the pool. Such rules would expedite the formation of the necessary unit operation and the implementation of the waterflood scheme.

CHEVRON

Chevron agreed that waterflooding is necessary and would enhance total oil recovery. However, as operator of the 10-17 gas cap well, Chevron disagreed with the applicant's request for the gas-cap wells to be shut in as it observed little difference in recovery improvement in Case 3A over Case 4. Chevron submitted that unrestricted gas cap production combined with the implemented waterflood scheme would best protect the equity of the gas cap owners and based on energy content would provide the second highest recovery from the pool.

Chevron commented that further study on optimizing injection locations may prove advantageous. When questioned whether Case 3A, in which the gas cap wells are shut in, would have a negative impact on its gas plant, Chevron stated that in the long term it would not. However, Chevron submitted that the plant has a capacity of $761 \times 10^3 m^3/d$ with a turn-down rate of $338 \times 10^3 m^3/d$. The volume of gas being produced presently is $423 \times 10^3 m^3/d$. Chevron contended that other sources of gas are available but these would require the drilling of additional wells or recompleting

of existing wells. It acknowledged that modifications to the plant would be another alternative to reduce the plant turn down rate.

4 VIEWS OF THE BOARD

The Board observes that all participants in the hearing, including those with oil zone, transition zone and gas cap production, are unanimous in the conclusion that a waterflood scheme would substantially enhance oil recovery in the pool. Also, although there is some reservation respecting the optimum location of injection wells, it appeared that the three injection locations proposed by Pembina would go a considerable way toward achieving effective flood coverage. The Board concurs with this view and believes an appropriate waterflood scheme, along the lines proposed by the applicant, should be proceeded with as soon as practicable.

The remaining points at issue are:

a) Whether or not concurrent gas cap production should continue and if so, at what rate and from which wells should production be allowed?

b) Will a Board ruling on the terms of the waterflood approval and the permitted rate and location of gas cap withdrawals prejudice equitable operating arrangements among owners in the pool?

Concurrent Gas Cap Production

The Board is satisfied that continued concurrent production at current gas cap rates and under the current oil zone recovery mechanism would result in losses in otherwise recoverable oil. However, the example of injecting water in Lsd 11-12 demonstrated that liquid fill-up in that region of the pool would materialize as the waterflood displacement progresses thereby essentially eliminating the adverse pressure depletion effects occurring from gas cap withdrawals. Also, gas cap withdrawals more remote from the oil zone region would appear to have much less effect on waterflood control than those close to the oil zone region. On the other hand maximizing withdrawals from the transition region (11-7 and 2-13) would clearly increase oil recovery potential.

On the basis of these observations and its review of the evidence presented, the Board has concluded that totally closing in the gas cap for a lengthy time period would not significantly enhance total hydrocarbon recovery from the pool and cannot be justified. On the other hand, the Board is of the view, assuming that water injection proceeds at the three injection wells applied for, that some method of phased control of both gas cap and oil zone reservoir withdrawals should be implemented in order for the waterflood to be fully effective and to maximize total recovery from the pool. This is because some period of liquid fill-up in Area 3 will be required before any tangible response is attained in the immediate area of the injection wells and excessive reservoir withdrawals would not only lengthen this period but also severely test the capacity of the flood to correct and enhance production performance. Furthermore, as

unrestricted gas cap production would significantly exceed the depletion rates investigated by the applicant, the Board believes that totally uncontrolled depletion of the gas cap may greatly increase oil migration and hence magnify the detrimental effects on ultimate oil recovery.

Looking only at the areas of interest (Areas 3, 4 and 5 referred to in the Reservoir Engineering Study) the Board envisages that all of the wells in these lands would remain shut in for an initial period, possibly of some six months following commencement of injection. This would maximize the effects of water injection and minimize the liquid fill-up time in Area 3. Also it would reduce the effects of pressure depletion resulting from continuous gas cap withdrawals in both the transition zone (Area 4) and the gas cap (Area 5). As liquid fill-up is achieved within the 6 month period, the offsetting oil wells may be phased back on production. By extrapolating the experience obtained in other pools it would appear that full flood response could be obtained out to but not including the transition wells in a period of possibly 12 to 18 months. After that time the Board believes that controlled withdrawals from the transition wells as well as the gas cap wells would not adversely affect waterflood efficiency performance and would enhance total hydrocarbon recovery from the pool. Moreover, on the basis of investigation of water injection at 11-12, the Board believes that a more optimum updip location or more appropriate injection rates might be established which would possibly allow for earlier commencement of withdrawals from the transition region and might even permit those withdrawals to occur at unlimited rates.

Effect of Board Decision on Ownership Interests

The Board believes its primary responsibility is to ensure that effective conservation practices are incorporated into the mode of operating the subject pool. It does not have a direct involvement in unit negotiations but recognizes that any firm decision it makes now which fixes the conditions under which wells might be operated could indirectly affect the negotiating position of the various owner interests in establishing a unit. Also, the Board understands that while there is no real need or purpose for the owners of the three gas cap wells to become part of an oil producing unit, the owners of those gas wells are nevertheless affected by production restrictions that might be imposed. The Board notes that most of the participants in the hearing recognized the complexity of the problem and saw some merit in the Board either setting rules of operation that it thought would be most fair and equitable or, alternatively allowing some period of grace for the operators to develop satisfactory operating agreements among themselves. If this could not be accomplished, certain of the participants held the view that those areas of the pool which are involved (Areas 3, 4 and 5) should be shut in and would remain shut in until agreements were reached. The Board believes the latter course offers the most expeditious procedure for reaching satisfactory arrangements to optimize hydrocarbon recovery from the pool.

5 DECISION

The Board has decided to grant the part of the application pertaining to conversion of the three injection wells for waterflood service and will issue an approval for that purpose. The area of approval for waterflood cannot be defined at this time and will not be shown in the approval.

The Board will allow the current form of oil well allowables and concurrent production operations under Order No. Misc. 8121 to remain in effect until 31 December 1982. After that date if a suitable scheme for waterflooding and gas cap withdrawal acceptable to owners in the pool and to the Board has not been agreed upon, Order No. Misc. 8121 would be suspended such that permitted cap withdrawals would be nil and also the MRL's for oil wells would be suspended such that oil production allowables would be nil.

DATED at Calgary, Alberta on 4 June 1982.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

N. Strom, P.Eng.
Board Member

J. R. Pow, P.Eng
Acting Board Member

TABLE 1

CASE	DESCRIPTION	AREAS (3) & (4): OIL IN-PLACE = 851 x $10^3 m^3$		POOL TOTAL: OIL IN-PLACE = 1880 x $10^3 m^3$		POOL TOTAL: GAS IN-PLACE = 940 x $10^6 m^3$
		RECOVERY FACTOR	RECOVERABLE OIL	RECOVERY FACTOR	RECOVERABLE OIL	RECOVERABLE GAS CAP GAS
		fraction	$10^3 m^3$	fraction	$10^3 m^3$	$10^6 m^3$
CASE 1	Concurrent production is continued at current 110 x $10^3 m^3$/d total restriction. Gas is restricted to 14 x $10^3 m^3$/day/well for each well producing only gas with the 11-7 and 2-13 wells producing at capacity.	0.130	110	0.206	386	773
CASE 2	The gas cap wells are shut in but the 11-7 and 2-13 wells are allowed to produce at capacity. The gas cap wells are allowed to commence production in the year 2001 at a restricted rate of 14.057 x $10^3 m^3$/day/well.	0.137	117	0.215	404	743
CASE 3A	A waterflood scheme is implemented to replace oil voidage and the gas cap wells are shut in. The 11-7 and 2-13 wells are allowed to produce 51 x $10^3 m^3$/d. Gas blowdown commences in the year 2001.	0.324	276	0.367	68[illegible]	744
CASE 3B	A waterflood scheme is implemented to replace oil voidage and the gas cap wells are shut in. The 11-7 well is shut in until the year 2001 while the 2-13 well is allowed to produce at 25.5 x $10^3 m^3$/d. Gas cap blowdown commences in the year 2001.	0.325	277	0.369	691	711
CASE 3C	A waterflood scheme is implemented to replace oil voidage and the gas cap and transition wells are shut in. Gas cap blowdown commences in the year 2001 when the gas cap and transition wells are placed on production.	0.288	245	0.352	[illegible]	714

TABLE 1 (CONT'D)

CASE	DESCRIPTION	AREAS (3) & (4) OIL IN-PLACE = $851 \times 10^3 m^3$ RECOVERY FACTOR fraction	AREAS (3) & (4) RECOVERABLE OIL $10^3 m^3$	POOL TOTAL OIL IN-PLACE = $1880 \times 10^3 m^3$ RECOVERY FACTOR fraction	POOL TOTAL RECOVERABLE OIL $10^3 m^3$	POOL TOTAL GAS IN-PLACE = $940 \times 10^6 m^3$ RECOVERABLE GAS CAP GAS $10^6 m^3$
CASE 4	A waterflood scheme is implemented to replace oil voidage but the gas cap and transition wells are left on production at a restricted rate of $14 \times 10^3 m^3$/d/well (or 70×10^3 m^3/d total).	0.310	264	0.363	680	778
CASE 5	A waterflood scheme is implemented to replace oil voidage and a water-fence is included to replace gas cap voidage. The gas cap and transition wells are allowed to produce at a restricted rate of $14 \times 10^3 m^3$/d/well.	0.345	294	0.380	712	760
CASE 6	A waterflood scheme is implemented to replace oil voidage with an additional injector at 11-12. Other conditions were maintained as close as possible to CASE 3A.	0.309	263	0.364	684	771
CASE 7	A waterflood scheme is implemented to replace oil voidage with an additional injector at 11-12. Other conditions were maintained as in CASE 4.	0.306	260	0.363	681	779

Table 2

Illustrative Present Worth Balances Including
Special Royalty Rebate Concessions for Small Companies
and Modified by Board to Show
Transition Zone Division

Present Worth ($ thousands)

Case	Oil Zone Area 3 Oil & Gas	Transition Zone Area 4 Oil	Transition Zone Area 4 Gas	Gas Cap Area 5 Gas
			(Sharing required)	
Case 3A	5 350	1 905	6 298	37
Case 3B	5 596	1 582	4 484	171
Case 3C	6 432	207	365	545
Reference Case				
Case 4	4 825	1 873	3 994	4 174
Case 5	7 145	1 402	1 301	2 888
Case 6 [1]	5 227	2 022	5 796	1 498
Case 7	5 087	1 832	3 854	4 222

Unrestricted Gas Cap Withdrawals - Not Evaluated by D&S

1 Gas Cap wells put on production in 1982 to maintain gas withdrawal rate comparable with Case 3A

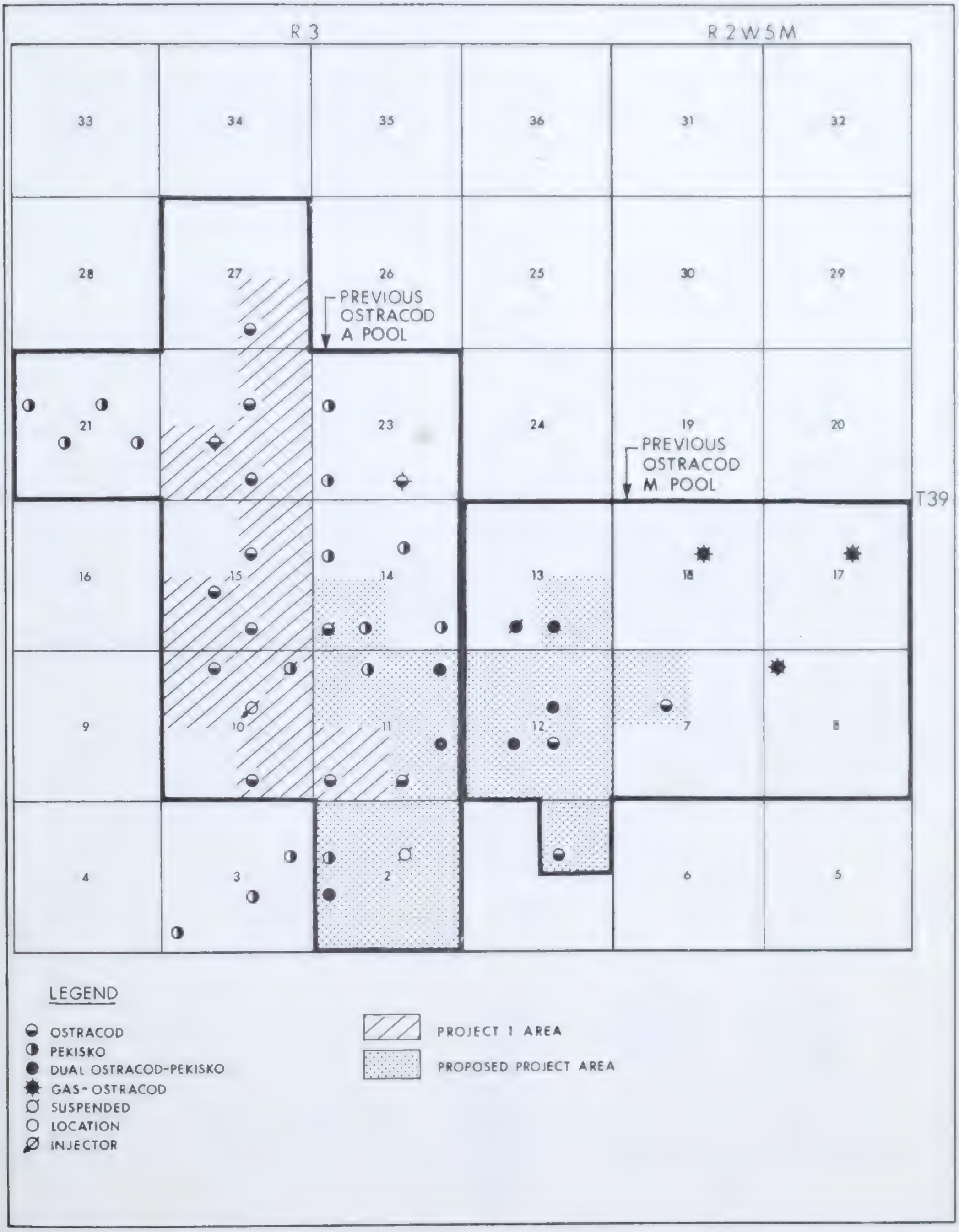

FIGURE 1 MEDICINE RIVER OSTRACOD A POOL

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA CANADA

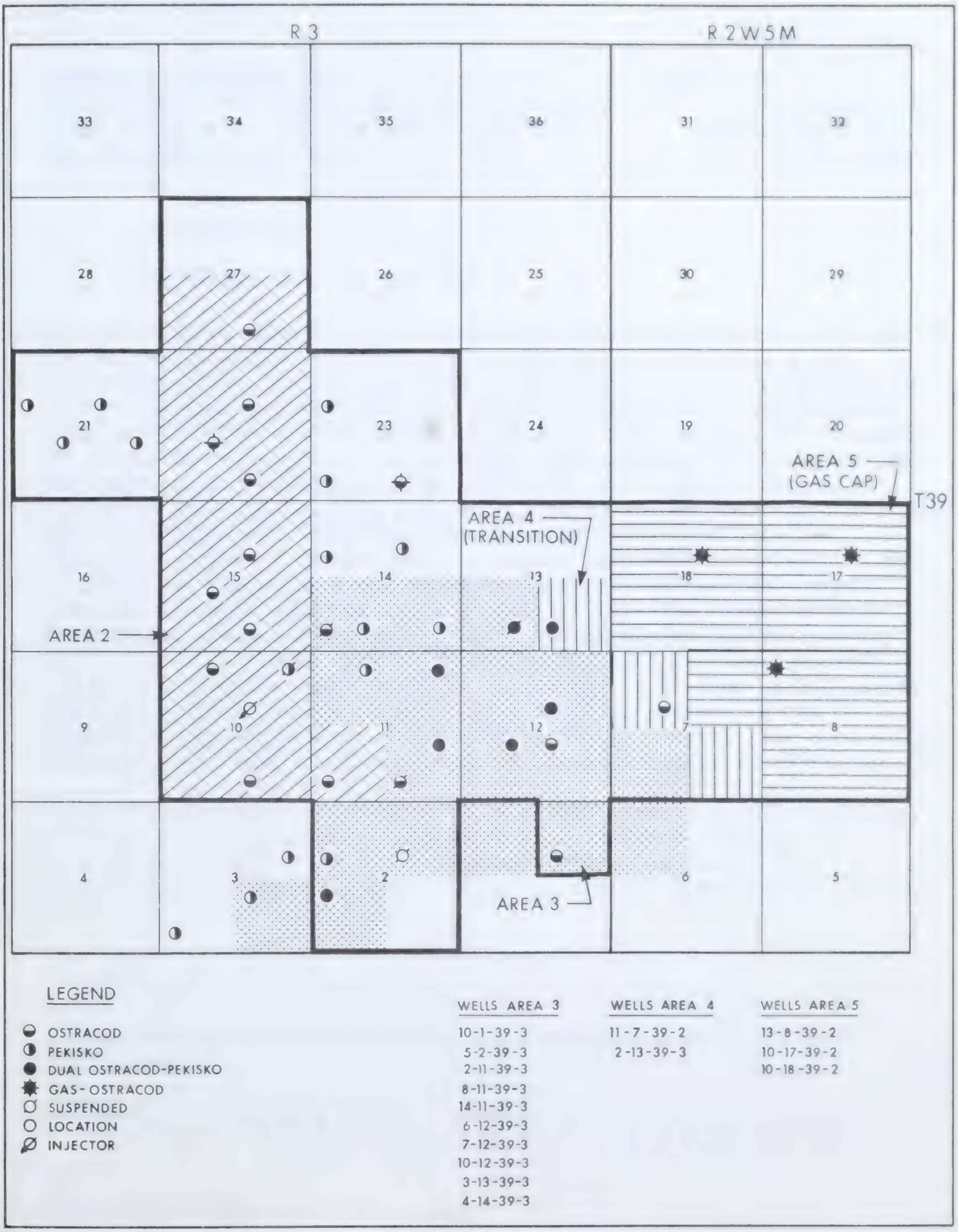

FIGURE 2 MEDICINE RIVER OSTRACOD A POOL. Study areas

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

INVERNESS PETROLEUM LTD.
APPLICATIONS FOR APPROVAL OF A GAS PROCESSING PLANT AND RELATED GAS GATHERING FACILITIES IN THE SILVER VALLEY AREA

Decision 82-21
Applications 810434 and 820033

1 INTRODUCTION

1.1 The Application and Hearing

Inverness Petroleum Ltd. (Inverness) applied, pursuant to section 38[1] of the Oil and Gas Conservation Act for approval to construct a gas processing plant, and under part 4 of the Pipeline Act for approval to install related gas gathering and pipeline facilities. The proposed plant would be located in legal subdivision 13 of section 27, township 81, range 11, west of the 6th meridian approximately 7 kilometres (km) northwest of Silver Valley. The gathering system would initially transport sour gas from two gas wells located in Lsd 10-21-81-11 W6M and Lsd 11-28-81-11 W6M, although Inverness has plans to tie-in two additional wells in the future to maintain gas contract volumes. The two proposed gathering lines would be 88.9 millimetres (mm) outside diameter and both would be level 1[2] facilities. The plant would be designed to process a maximum of 84.95 thousand cubic metres per day (10^3 m^3/d) of raw gas, from which 81.2 x 10^3 m^3/d of sales gas and 3.1 m^3/d of pentanes plus would be recovered. A maximum of 3.0 tonnes per day (t/d) of sulphur dioxide (SO_2) would be emitted to the atmosphere through a flare stack 45.7 metres in height. The area around the applied-for plant and pipelines is shown on the attached figure.

The applications were considered at a public hearing in Silver Valley, Alberta, on 22 and 23 March 1982 with G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and C. J. Goodman, P.Eng., sitting. The participants in the hearing are listed in the following table.

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1 Now section 26 of the Oil and Gas Conservation Act (RSA 1980, c. 0-5).

2 Facilities having potential hydrogen sulphide release volumes of less than 300 m^3 as defined in ERCB Interim Directive 81-3.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Inverness Petroleum Ltd. (Inverness) A. L. McLarty	A. H. Anderson, P.Eng. D.P.E. Bustin, P.Eng. of R.D. Niven Consulting Engineers Ltd. L. J. Knapik, P.Ag. of Pedology Consultants J. A. Lore, P.Ag. of McKinnon, Allen & Associates (Western) Ltd. G. L. Brown and D. M. Leahey of Western Research and Development Ltd.
Josephine Environmental Protection Group (Josephine Group) J. D. Carter	A. B. Rehaume J. E. Umbach K. Scobel D. M. Baxter K. R. Travis B. M. Phillips K. Weiss H. D. Brown R. Harpe H. Nagel
National Farmers Union (NFU) M. E. Staton	M. E. Staton J. Hendricks
A. H. Johnstone	A. H. Johnstone
Alberta Environment C. S. Liu, P.Eng. J. Defir, P.Eng. D. Graveland, P.Ag.	
Energy Resources Conservation Board staff M. J. Bruni E. P. Moeller, C.E.T. I. Weleschuk, P.Ag. B. C. Hubbard, P.Eng.	

2 INTERVENTIONS

The Josephine Environmental Protection Group was the principal intervener and is made up of farmers, landowners, and residents of the Silver Valley-Bonanza area. The Group's submission dealt with SO_2 which would be emitted from the proposed plant and its relation to air quality, sulphur deposition, selenium deficiency, soil pH, contamination of water supplies, health, and public safety. The Josephine Group suggested the following alternatives for the Board to consider:

- If the plant were approved at the proposed location, Inverness be requested to recover sulphur to the limit of existing technology.

- Alternatively, pipe the raw gas to some larger facility which is currently recovering sulphur.

- The ERCB establish a policy requiring operators of proposed small sour gas plants in areas of sensitive soils to amalgamate their sour gas facilities into one plant, which would be required to recover sulphur to the limits of existing technology.

- If none of the above solutions are currently feasible, the construction of the plant should be postponed until one becomes feasible.

The NFU appeared at the hearing to support the Josephine Group, and to draw attention to its own general concern about the impact of plant emissions on agriculture.

Mr. Johnstone intervened to give his view on the need for a soil sampling and pH measurement study in the Peace River block.

Alberta Environment appeared for purposes of cross-examination only.

3 ISSUES

3.1 The Plant

The Board believes the issues fall into two major categories: first, whether or not the plant as proposed, without sulphur extraction, would meet provincial standards respecting environment protection, resource conservation and public safety. The second issue is whether or not sulphur recovery should be required on the basis of the position of some interveners that adverse economic and health effects would occur if sulphur were not recovered.

To appraise the first principal issue, the Board summarizes the evidence presented and gives its views regarding two sub issues:

- Is there a requirement, on the part of Inverness, for gas processing in the area?
- Are conservation and technical aspects satisfactory and would the plant meet provincial standards regarding environmental impact and public safety?

If the Board finds the plant satisfies the above-mentioned criteria, it will then consider whether the release of 3 t/d of SO_2 would have significant economic and health effects in the community. The following matters appear to the Board to bear on this second major issue.

- Are there alternatives available such as processing the gas at some other location?
- What are the economic and practical ramifications of installing sulphur recovery equipment at the plant, the environmental and economic consequences of the emissions from the plant on the neighbouring community, and is there a related need for sulphur recovery?

In addition to the two principal issues which are set out in detail above, some interveners raised the issue of proliferation of small plants, which would not be required to recover sulphur, compared with a single large plant where sulphur recovery would be practical.

3.2 Pipelines

If the plant application is approved, the Board will deal with the pipeline applications under the general issue of suitability of the proposed pipelines with respect to need, route, technical aspects, and public safety.

4 REQUIREMENT FOR PROCESSING CAPACITY IN THE AREA

4.1 Applicant's Views

Inverness stated that it owns natural gas wells in the area, has a firm gas contract with Pan-Alberta Gas Ltd. (Pan-Alberta) to sell gas in 1982, and must now start to produce the shut-in reserves in order to

satisfy the contract and realize some return on its investment. According to the terms of the contract with Pan-Alberta, Inverness must process the sour natural gas to remove sulphur so that it meet sales gas specifications.

4.2 Interveners' Views

The majority of the interveners did not question the need for a gas plant but were concerned with the effect of its operation. The Josephine Group suggested that it might be feasible to transport the gas to some existing plant for processing outside the Silver Valley area.

4.3 Board's Views

The Board recognizes that Inverness has proven gas reserves in the Silver Valley area and a sales contract with Pan-Alberta. Since the gas is slightly sour, if it is to be produced and marketed it must be processed. There is consequently a need for either a processing plant in the area or for a pipeline to an existing facility. The matter of alternative processing locations is discussed in subsequent sections of this report.

5 RESOURCE CONSERVATION, SAFETY AND ENVIRONMENTAL STANDARDS

5.1 Applicant's Views

Inverness submitted that the plant process would consist of inlet separation, dehydration, stabilization, sweetening, and the subsequent flaring of the acid gases.

The plant would be designed and constructed to safely process sour gas. The process would allow a maximum of 84.95×10^3 m^3/d of raw gas containing 1.31 mole per cent hydrogen sulphide (H_2S) to enter the inlet separator where free condensate and water would be removed. Condensate would be separated, stabilized, and trucked to market. Remaining moisture in the gas would be removed in the dehydration process. Dry gas containing H_2S and carbon dioxide (CO_2) would enter a sweetening unit where the acid gas would be separated to produce sales gas. The stripped acid gas would then be burnt at the top of a 45.7 metre flare stack to convert the H_2S to SO_2. Inverness stated that the proposed plant would conform to all Provincial Government regulations respecting maintenance of air quality standards.

Inverness said that the proposed plant and gas gathering facilities would cost some \$2.76 million of which \$2.3 million would be the cost of the plant. If sulphur recovery were required the process facilities would be based on design capacity and would cost an additional 46 per cent of the plant cost (over \$1 million) to achieve 90 per cent sulphur recovery.

Although the plant would be designed to process 84.95×10^3 m^3/d of raw gas to meet contract "peak day" volume requirements, Inverness stated that the plant would normally operate at only 60 per cent of design capacity and would occasionally be shut in completely. In the future, additional wells might be connected to the plant to maintain contract volumes but Inverness did not anticipate that the plant would ever require expansion during its 20-year life.

Inverness described the emergency shutdown system and H_2S detection equipment that would be installed at the wellsites and the plant to ensure that a release of H_2S would not go undetected and uncontrolled. The applicant stated that the plant would be manned part time but that an operator would check the plant and wells at least twice each day. The plant would also be equipped with a master control panel that would signal a malfunction by an alarm to the operator who would live no further away than the Town of Bonanza which is some 20 km to the southwest.

5.2 Interveners' Views

Interveners expressed concern with the safety of the proposed plant since it would not be manned full time. They were concerned about the length of time it would take the operator to reignite the flare stack in the event that the flame went out, thus allowing unburned H_2S gas to vent from the stack. Other than Alberta Environment, none of the process design details of the plant application were questioned by the interveners other than the matter of sulphur recovery. The interveners suggested that Inverness should not have dismissed sulphur recovery for its proposed plant simply because it could achieve the provincial air quality standards since the sulphur emissions could still have an impact on the surrounding area.

5.3 Board's Views

The Board is satisfied that the design and the conservation aspects of the proposed plant are technically sound. The Board also concludes that the proposed plant would not exceed the maximum permissible SO_2 concentrations set out by Alberta Environment's Clean Air Regulation

under any normal operating condition. In a separate section of the report the Board will consider the interveners' contention that sulphur recovery should be required notwithstanding that the plant meets the pollution control regulations.

Regarding the interveners' concerns about safety of residents in the vicinity of the plant, the Board is satisfied, having regard for the very small size of the plant and for the relatively low concentration of H_2S in the gas to be processed, that the safety devices proposed by the applicant to control a possible release of sour gas are adequate. In addition, the Board notes that the plant, while not physically attended on a continuous basis, would be monitored on a 24-hour basis through the emergency warning system connected to the plant operator's residence. The Board considers this surveillance adequate, given the automatic controls, the low H_2S content of the gas, the small plant size, and the twice daily visits proposed by the operator.

6 ALTERNATIVES

6.1 Interveners' Views

The Josephine Group asked Inverness whether it had considered processing its gas at existing gas plants such as those located at Taylor, British Columbia, or the Golden Eagle Oil and Gas Company plant at Boundary Lake, or the Dome Petroleum Limited plant at Braeburn. The Josephine Group suggested that if it were feasible to process the gas at an existing facility, it would eliminate the need for a new processing facility in the Silver Valley area and would eliminate any environmental damage associated with the proposed plant.

6.2 Applicant's Views

Inverness stated that it had considered processing its gas at the above-mentioned plants, however, additional pipeline length and economics made these alternatives much less attractive than constructing a new plant in the area. To process the gas at the plant at Taylor, 45 miles (72 km) of pipeline would be required to transport the sour gas from the Silver Valley area. The pipeline would cross three rivers including the Peace River, and would cost approximately $4.8 million. To process the gas at the plant at Boundary Lake, 30 miles (48 km) of pipeline costing $3.6 million would be required and the line would cross the Peace River. Aside from the cost of these two alternatives, Inverness considered the additional environmental disturbance and possible land use restrictions associated with the longer sour gas pipelines (because of the higher potential H_2S release volume) to be negative aspects of these alternatives.

Inverness stated the plant at Braeburn did not have sufficient capacity available to handle gas from the Silver Valley area and considered that a plant expansion at Braeburn would be uneconomic.

6.3 Board's Views

The Board agrees that a lengthy sour gas pipeline, required to transport gas to any of the three existing plants, would be a disadvantage. The length of the pipelines to the alternative locations would result in additional surface disturbances on the right of way and increased environmental impact at river crossings. In addition, the lengths of the required pipelines would result in higher potential release volumes of sour gas and would therefore be a somewhat more hazardous facility. Although the Board does not consider these disadvantages could not be mitigated, it does consider they should be avoided if possible.

The applicant's cost figures for the alternatives also indicate that a new processing facility as proposed is a more economic choice. At an estimated cost of $2.76 million, the proposed plant and gathering system would cost approximately $2 million less than the pipeline required to transport the gas to the plant at Taylor, and approximately $800 thousand less than the pipeline required to transport the gas to the plant at Boundary Lake. Although the applicant did not estimate a cost figure for the Braeburn plant alternative, the Board estimates a $3 million pipeline cost exclusive of any cost for plant modifications to accommodate Inverness' gas.

On the basis of the environmental and other impacts of the required pipelines, and the increased costs, the Board concludes that moving the gas to existing plants for processing would not be more in the public interest than would a new plant in the area.

7 NEED FOR SULPHUR RECOVERY

The Board believes that in order to address the matter of whether or not sulphur recovery should be required at the proposed plant, the pattern of expected rates of sulphur deposition on the area surrounding the proposed plant must be determined and the impact resulting from the expected sulphur deposition examined. This section of the report addresses these matters.

7.1 Sulphur Deposition Modelling

7.1.1 Applicant's Views

The applicant used a mathematical model, adopted by Alberta Environment, to evaluate the potential effects of SO_2 emissions from the proposed plant on soil and water, and to predict the pattern and rate of sulphur deposition. The applicant said that the model predicated a maximum sulphur deposition rate of 5 kg/ha/yr in a relatively small area near the plant and that approximately six per cent of the total emitted sulphur would be deposited within a radius of 15 km of the plant. The deposition rate would be comparable to the global background rate of 5 to 6 kg/ha/yr of deposition that occurs from natural and industrial sources, such as the decay of vegetation, sea spray, and emissions from heavily industrialized parts of the world.

Inverness explained that it used weather data from the Grande Prairie airport as input into the deposition model since it was the nearest weather station to the proposed plant location. In response to a suggestion by interveners that using the Grande Prairie weather data was inappropriate, the applicant stated that even if wind data were used from an area having significantly different weather patterns, the predicted deposition patterns for a given year might vary by as much as a factor of three but that the predicted maximum deposition rate would vary by much less than this. The applicant argued that in determining the impact of SO_2 deposition the interveners assumed the predicted maximum deposition rate would occur within the entire region under consideration, and as a result the impact would be over-estimated.

The applicant also expressed the opinion that the topography of the area surrounding the plant, including the hill southeast of the plant, would have no effect on the predicted sulphur deposition rates.

7.1.2 Interveners' Views

The Josephine Group questioned the input data, and therefore the results of the calculations performed by the applicant to predict the pattern of SO_2 deposition resulting from the proposed plant. The group argued that:

1. The applicant did not take into consideration the effects of topography. For example, a prominent hill some 7.5 km southeast of the proposed plant is at the same elevation as the proposed stack height.

2. The weather data from the Grande Prairie airport is significantly different from the weather patterns in the vicinity of the proposed plant. Also, the close proximity of the Peace River increases the prevalence of fog conditions in the area.

3. The model used by the applicant has never been tested or proven to be accurate.

The interveners then presented their own calculations of sulphur deposition rates on a circular area centred at the plant. They assumed that 50 per cent of the sulphur emitted by the plant would be deposited within a 14-km radius of the stack, and would be spread evenly over this entire area. The calculation resulted in an estimate of sulphur deposition of 4.6 kg/ha/yr over a circle of 14 km.

7.1.3 Board's Views

The Board has considered both the applicant's SO_2 deposition calculations and the calculations of the interveners, and all evidence of this nature presented at the hearing. It concludes as follows:

1. Diffusion modelling is a useful although semiquantitative science at the present time. Consequently, the Board would not base its conclusions entirely on the results of modelling calculations in the face of conflicting evidence. However, the interveners' estimate of 50 per cent deposition of emissions within a 14-km radius was given without adequate scientific support, and therefore appears to the Board to be hypothetical. The evidence presented by the applicant appears to be based on the present-day state of knowledge in diffusion meteorology. For the purpose of this decision, the Board therefore accepts the evidence of the applicant as the most reasonable, both with respect to the amount of deposition and the pattern and location of the deposition relative to the proposed plant site.

2. The elevation of the hill some 7.5 km southeast of the proposed plant is not sufficient to significantly influence the atmospheric diffusion of SO_2 emissions.

3. There was no evidence to support the contention that locally prevalent fog conditions increase the rate of wet deposition of sulphur compounds. The Board understands that wet deposition in Alberta is insignificant in comparison to total deposition, and it believes that this would likely also apply to the Silver Valley area.

7.2 Human Health Effects

7.2.1 Applicant's Views

Inverness stated that emissions from its proposed plant would not exceed the maximum allowable levels specified in the Clean Air Regulations which are enforced by Alberta Environment, and compliance with government standards meant that the plant emissions would not threaten human health or the environment. Thus, Inverness saw no need to undertake an investigation into the appropriateness of the Clean Air standards.

Inverness noted that it had examined the possibility of plant SO_2 emissions acidifying the local residents' domestic water supply dugouts. However, through sampling a number of dugouts, it found that the water was naturally well-buffered and that the emissions would not cause any change in pH.

7.2.2 Interveners' Views

The interveners submitted that complying with the Clean Air Regulations did not guarantee that the plant emissions would not affect human health, and that compliance with the regulations should not relieve the applicant of the responsibility of assessing the effects of its emissions. One concern was that the emissions might lead to increased respiratory health problems for local residents. A second concern was that the SO_2 emissions might acidify domestic water supplies stored in open dugout reservoirs. By lowering the pH, the acidic water could possibly dissolve heavy metals present in the soil and result in their concentration to toxic levels in the dugouts.

7.2.3 Board's Views

Although the Board is satisfied that the plant has been designed to conform to Alberta Clean Air Regulations, it recognizes the nature of the public health concerns expressed by the interveners. The Board is not aware, however, of any studies undertaken to date that have demonstrated that the Clean Air Regulations presently enforced in Alberta are not appropriate. For this reason, and because no evidence was presented at the hearing to convince the Board otherwise, the Board accepts the Alberta Clean Air Regulations as being appropriate, and concludes that the expected plant emissions should not affect the health of local residents.

With regard to the interveners' concern that their water supplies would become acidic as a result of the plant emissions, the Board notes the applicant's evidence that the dugout water is well-buffered and would be resistent to any pH change. Notwithstanding this, because of the importance of the domestic water supply to the residents, the Board believes that if the plant application is approved Inverness should establish, in consultation with Alberta Environment and the local residents, a water quality monitoring program of the water supplies in the area.

7.3 Economic Impact on Agriculture

7.3.1 Interveners' Views

The Josephine Group was very concerned with the effects that SO_2 emissions would have on soils in the Silver Valley area. It contended that SO_2 deposition would increase soil acidification rates and that the resulting cost of restoring the agricultural productivity would impose an economic loss on local farmers.

To support this contention, calculations were presented to show the effect of lime additions to local soils. The group assumed, for the purposes of the calculations, that soil pH increase as a function of liming rate is identical to soil pH reduction as a function of acid deposition rates. On this basis, and by using its own deposition estimate, the Josephine Group concluded that the soils in the area would be acidified to the extent of 0.1 pH unit over the lifetime of the proposed plant. It was further argued that the effect of this degree of acidification on crop yields would represent a substantial economic loss to farmers in the area.

Calculations suggesting significant economic loss to farmers were also prepared with respect to livestock diseases. It was argued that marginal trace element concentrations in local soils and forages would be reduced to deficiency levels by SO_2 emissions from the plant. In order to prevent livestock diseases related to nutritional deficiencies of these elements, notably copper and selenium, supplementation of diets or injection of animals with trace element preparations would become necessary.

Further concerns were raised with respect to acceleration of metal corrosion and property devaluation in the proximity of the proposed plant site.

7.3.2 Applicant's Views

The applicant argued that the studies used by the Josephine Group to support its case that SO_2 causes pH reduction in soils were studies involving potted soils and that similar data was not found when field plots were used. Given such data, the applicant contended that there was no evidence to suggest that any levels of SO_2 emissions have an acidifying effect upon soils under field conditions.

The applicant's agricultural consultant was of the opinion that the sulphur-selenium-copper interrelationship was not well understood in cattle and therefore it would be very difficult, if not impossible, to deduce a causal relationship between nutritional levels of these trace minerals in local feedstuffs and the ultimate levels of absorbtion by local animals. He pointed out that selenium deficiency symptoms may be induced or affected by a number of nutritional parameters.

It was argued that the present level of nutritional selenium available to livestock in locally grown feedstuffs warrants selenium supplementation at present, and therefore the proposed plant should not be charged with the economic costs as suggested by the Josephine Group.

Further, the applicant submitted that concerns of metal corrosion and property devaluation were unwarranted because they could not be supported by evidence from similar plants elsewhere in Alberta.

7.3.3 Board's Views

The Board's views concerning SO_2 deposition have already been stated in section 7.1.3. In addition, the Board is not convinced that the results of the liming calculations presented by the Josephine Group can be used to predict the impact of acid deposition. The argument that they can be so used rests on the assumption of essentially complete reversibility of reactions of acids and bases in soils. The Board believes that this assumption is not, generally speaking, correct and notes that no evidence was presented to suggest that it might be applicable in this instance. Although the Board has reservations about the applicant's extrapolation of soil study results from southern Alberta to the Silver Valley area, it has no reason to believe that the small SO_2 depositions expected are not within the assimilative capacity of the Silver Valley area soils. Consequently, the Board does not believe that the emissions that would occur from the proposed plant would have a significant enough impact on the agricultural productivity of the area surrounding the plant to justify a requirement for sulphur recovery.

The Board notes that the operator of a sour gas plant is required to monitor the ambient air and soil pH in the vicinity of the plant. For example, soil pH samples are to be taken 50 m, 100 m, and 1, 2, and 8 km from the plant in the predominant downwind direction. The data, required by air monitoring directive AMD 81-1, are reported to Alberta Environment. The Board believes that this monitoring will provide the necessary data to evaluate any impact of the plant on air and land throughout its operating life. These data would also indicate to Alberta Environment, the Board, the applicant, and the public if and when remedial measures should be initiated by the plant operators.

With respect to the impact on livestock, the Board believes that the antagonistic relationship between sulphur and selenium or copper in animal nutrition, as assumed by the interveners, remains to be scientifically demonstrated at normal dietary levels. Further, the Board is aware that SO_2 emissions are only one of many sources of sulphur compounds in the environment. Accordingly, the Board does not believe that present-day scientific knowledge supports the existence of a causal relationship between SO_2 emissions and selenium or copper deficiency diseases in livestock, even though it recognizes this matter to be an appropriate field for scientific research. Having regard for the proposed SO_2 emission rates, the evidence presented at the hearing and the current understanding of the relationship between SO_2 emissions and livestock diseases, the Board does not believe that sulphur recovery from the proposed plant can be justified because of possible economic impacts on the livestock industry.

With respect to the concerns of accelerated corrosion of farm implements, and metal buildings and wire fences, no direct evidence was presented to show such an effect would occur near a plant of the size proposed. The Board notes the effects in other areas reported at the hearing, but believes that these occurred near oil well battery flare stacks which were not designed to conform with the current SO_2 ground level standards. Having regard for the small emissions expected from the proposed plant, there should not be a significant increase in the corrosion rate near the plant. The Board also doubts that the plant would have a significant effect on land values in the area.

7.4 Conclusions Respecting the Need for Sulphur Recovery

The Board concludes that the plant has been designed to meet or exceed all existing safety and pollution control standards. Having regard for the rate of emissions and the operating history of similar and substantially larger sized sour gas plants operating in the province, the Board believes that adequate safeguards will exist with regard to

air and water quality, and human and animal health through the operating life of the plant. Additionally, the Board believes that the deposition rates of SO_2 should not be sufficient to cause the acidification of the soils. Therefore, the Board does not believe that there is sufficient cause to justify the cost of installing sulphur recovery equipment at the proposed plant.

8 PLANT PROLIFERATION

8.1 Interveners' Views

The Josephine Group was concerned that other plants might be built in the area, and that a proliferation of them could occur which would adversely affect the area and its residents.

8.2 Applicant's Views

Inverness stated that it "has talked to other oil and gas producers in this area in particular. The best it has been able to determine there will be no other gas production in this area for at least the next three or four years, from other operators". It further stated "the alternative that then awaits this applicant is either to apply for approval to operate this gas plant now; or to await three or four years down the road when hopefully some other company will have by that time decided its ready to try to do something with respect to its producing".

8.3 Board's Views

The Board notes that more proved gas reserves exist in the immediate area than Inverness proposes to connect to its plant, and also recognizes that there are prospects for further development of additional gas reserves, some of which may contain low concentrations of H_2S. Since the proposed plant would have spare capacity, some of the gas could be processed at the plant. However, if the Inverness plant is constructed and the Board received an application to process additional gas, such that an expansion of the plant was necessary, it would require the applicant to give serious consideration to processing this additional gas through other existing plants or installing equipment to recover sulphur. Furthermore, if other plants were proposed in the immediate area, the Board would similarly require the proponent of such plants to investigate all alternatives including utilizing unused capacity or expansion of existing plants, and the installing of sulphur recovery equipment at those plants.

9 SUITABILITY OF THE PROPOSED PIPELINES

9.1 Applicant's Views

Inverness stated in its pipeline permit application to the Board that the proposed pipelines are required to transport raw natural gas from two wells to a central processing and sweetening facility. The gas is required to fulfill a contract with a gas purchaser.

The applicant further stated that the two proposed pipelines required to connect the wells with the proposed processing plant would cross agricultural land and that none of the affected landowners objected to the routing of the proposed lines.

The two proposed gathering lines have potential hydrogen sulphide release volumes of 8.6 m^3 and 13.9 m^3 as calculated in accordance with ERCB Interim Directive 81-3 and would be defined as Level 1 facilities by that directive.

9.2 Interveners' Views

Interveners at the hearing disputed the applicant's stated need to construct the proposed pipelines to transport gas from the wells to the proposed processing plant.

The Josephine Group expressed concern that a release of sour gas from the proposed pipelines could jeopardize the safety of residents in the area. This concern was based in part on the possibility of a mechanical failure that might prevent the emergency shutdown devices from operating if required, and in part on the limited number of evacuation routes available in the event of a release of sour gas.

9.3 Board's Views

The Board concurs with the applicant that the proposed pipelines would be required to transport gas from the 10-21 and 11-28 wells to the proposed processing facility in 13-27-81-11 W6M.

Although the pipeline design was not an issue at the hearing, the Board has reviewed the design details in the permit application and is satisfied that they meet the requirements of accepted design standards and regulations for sour gas pipelines in Alberta.

The Board notes the concerns of the Josephine Group regarding public safety in the vicinity of the proposed pipelines. The Board does not consider the proposed pipelines to pose a significant hazard to the residents in the area because: Board records of pipeline failures show that the chances of a sour gas pipeline failure are extremely remote, and the emergency shutdown equipment proposed by the applicant would limit the volume of hydrogen sulphide released to relatively small amounts (8.6 and 13.9 m^3), respectively. To emphasize the extremely small risk associated with the volume of hydrogen sulphide that could be released from the proposed pipelines, it should be noted that neither the Board nor the provincial planning authorities require any development setback from the pipeline right of way for sour gas lines containing up to 300 m^3 of hydrogen sulphide gas. Finally, even if the extremely unlikely combination of a pipeline failure and the failure of the emergency shutdown equipment occurred, thereby causing release from the pipeline to continue indefinitely, the Board believes that the hydrogen sulphide concentration of 13.1 mol/kmol in the gas that would be released would be rapidly diluted through mixing with the surrounding air. In the Board's view this would not result in an unsafe concentration by the time the gas reached the nearest residence approximately 600 metres away.

The Board, therefore, concludes that the pipeline is suitably designed and does not present a safety hazard to the nearby residents.

10 DECISION

Having considered all of the evidence, the Board finds that the proposed plant is in the public interest and is prepared to approve Application 810434 by Inverness for a new gas plant to be located in legal subdivision 13 of 27-81-11 W6M. The Board also approves Application 820033 by Inverness for pipelines to transport gas from two gas wells to the gas plant. The Board will issue the required approval and permits upon receipt of the necessary approval of the Minister of the Environment with respect to environmental matters.

DATED at Calgary, Alberta on 7th day of June 1982.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.

V E Bohme

V. E. Bohme, P.Eng.

C. J. Goodman

C. J. Goodman, P.Eng.

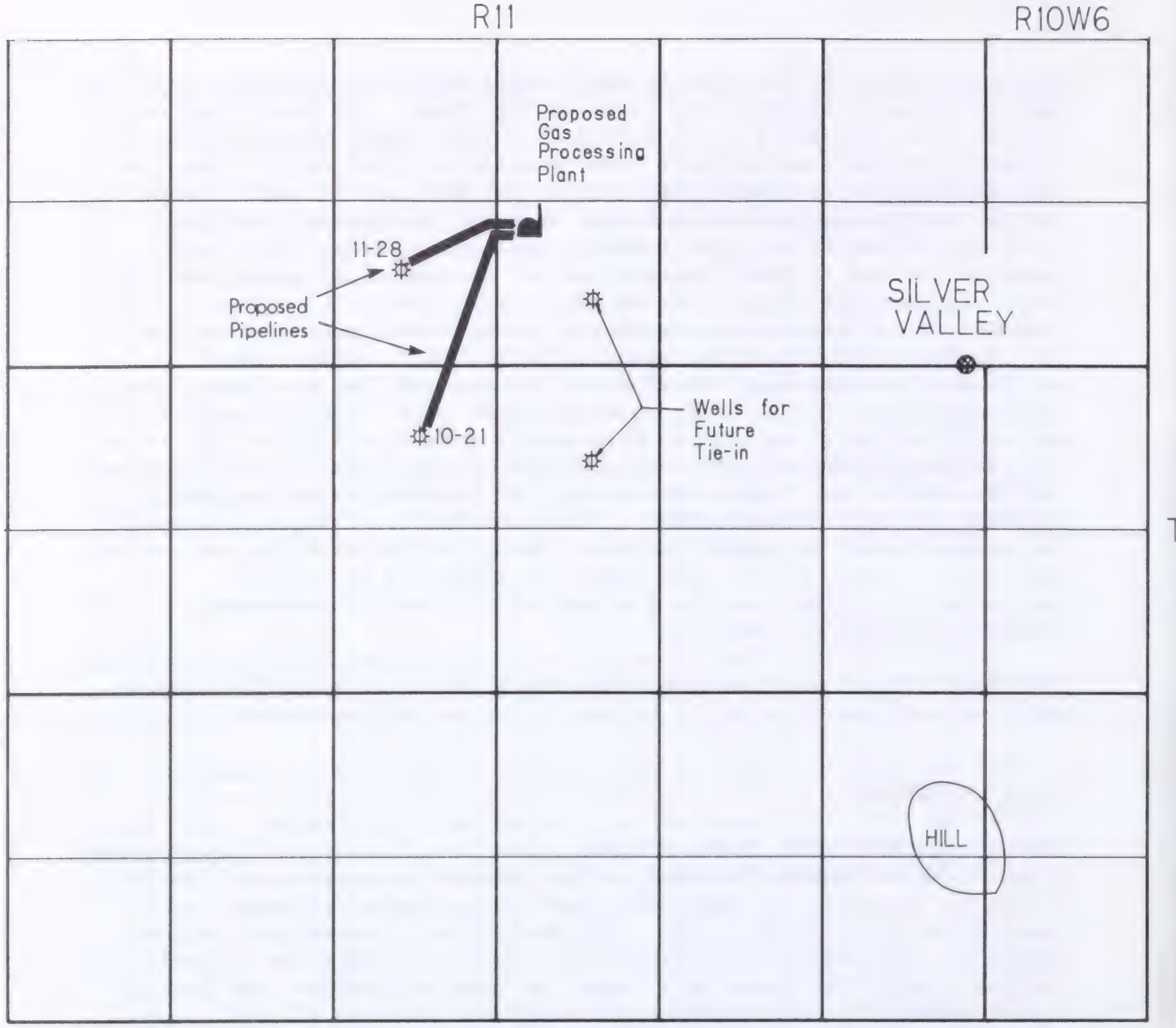

FIGURE 1 INVERNESS PROPOSED PLANT AND PIPELINES

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA CANADA

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY NORTHWESTERN UTILITIES LIMITED
FOR A PERMIT TO CONSTRUCT A GAS LINE
IN THE NORTHEAST EDMONTON AREA

Decision 82-22
Application 820083

1 THE APPLICATION

Northwestern Utilities Limited (NUL) applied for a permit to construct a gas line consisting of 27.4 kilometres (km) of 610 millimetres (mm) outside diameter (OD) pipe from legal subdivision 1, section 4, township 55, range 20, west of the 4th meridian to 2-31-53-22 W4M; 9.5 km of 762-mm OD pipe from 2-31-53-22 W4M to 3-21-53-23 W4M; and a meter/ regulator station in 3-21-53-23 W4M (Figure 1).

The purpose of the new pipeline would be to bring high pressure gas from existing NUL facilities to the Celanese methanol plant. The pipeline would also provide peak-load gas for the City of Edmonton from future salt cavern storage, and additional capacity to handle anticipated industrial loads in the Fort Saskatchewan area.

2 HEARING AND APPEARANCES

A hearing to consider the application was held in Edmonton on 15 and 16 April 1982 with G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and E. J. Morin, P.Eng., sitting. Those who appeared at the hearing are identified in the Appendix.

3 BACKGROUND

Within the past year, the Board considered applications for two major pipeline projects in the area northeast of Edmonton. The first was the Alberta Energy Company Ltd. (AEC) dual pipeline system to and from Cold Lake, and the second was the Shell Canada Limited (Shell) pipelines from the new refinery at Scotford. Because of the complexity of issues involved, the Board approved certain portions of the applications and

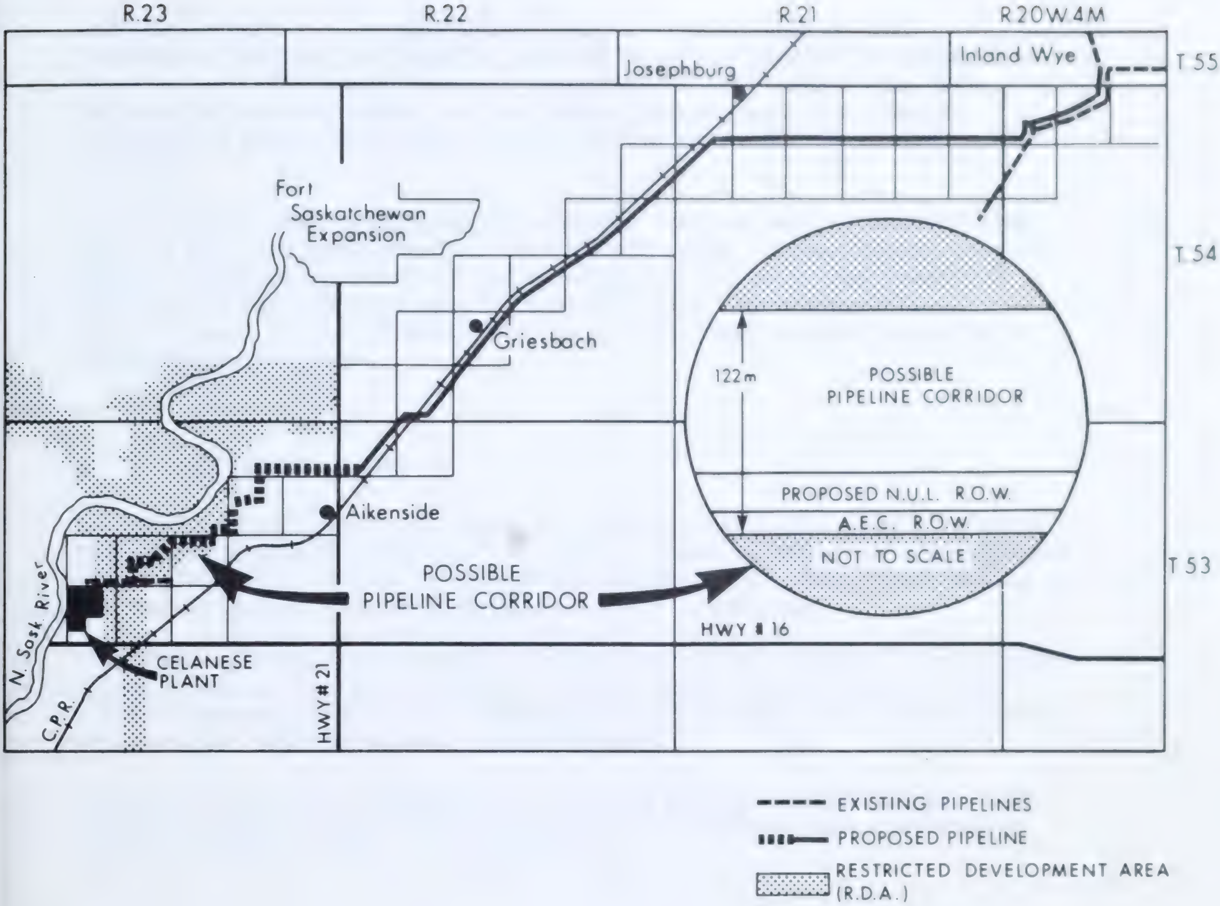

FIGURE 1 PROPOSED N.U.L. PIPELINE NORTHEAST EDMONTON AREA

deferred others[1,2,3] during which time, at the request of the Lieutenant Governor in Council, it held a public inquiry to consider a pipeline corridor route into the Edmonton refinery area.[4] To date, AEC has an approved route for its entire system, and Shell has an application before the Board concerning the remainder of its route into Edmonton.

It is against this background of multiple hearings and an inquiry that NUL has made its application. Part of the route follows along existing linear disturbances (railway and pipeline) and much of the remainder establishes new right of way. The application therefore, brings together many of the elements that were individual company concerns in the previous hearings.

4 THE INTERVENTIONS

A number of interveners had specific concerns about the manner in which the proposed pipeline would affect their property, while others supported the application. Figure 2 identifies the principal interveners making up the former group, and the location of their properties.

Drs. Shirvell and Simmons were concerned about the effect of the pipeline construction on the productivity of their land, and Dr. Shirvell was further concerned about the restrictions on the use of his property that would result from additional rights of way.

Schroter Enterprises believed that the new pipeline right of way would destroy valuable trees on its property, and wanted to see a sharing of space with the existing AEC right of way.

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1 Energy Resources Conservation Board, 1981. Applications for Permits to Construct Pipelines and Related Facilities Between Lloydminster and Cold Lake, and Between Edmonton and Cold Lake. ERCB Decision Report 81-7, Calgary, Alberta.

2 Energy Resources Conservation Board, 1981. Application for Permits to Construct Pipelines and Related Facilities in the Edmonton-Skaro Area. ERCB Decision Report 81-19, Calgary, Alberta.

3 Energy Resources Conservation Board, 1982. Applications by Alberta Energy Company Ltd. for Permits to Construct Oil Pipelines in the Northeast Edmonton Area. ERCB Decision Report 82-6, Calgary, Alberta.

4 Energy Resources Conservation Board, 1981. Northeast Edmonton Pipeline Corridor Inquiry. ERCB Decision Report 81-29, Calgary, Alberta.

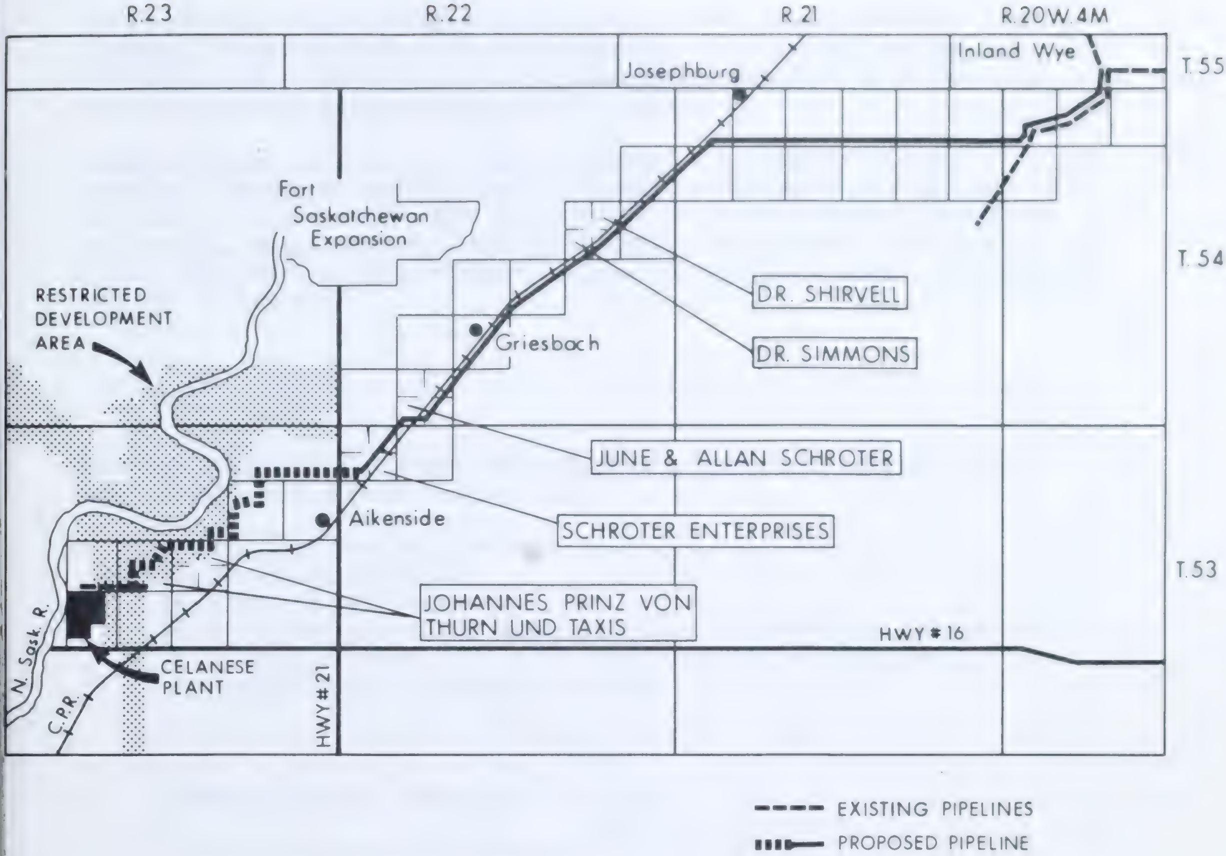

FIGURE 2 LOCATION OF INTERVENERS' PROPERTY

The concerns of the Schroters (June & Allan) were primarily with potential impact on future land development, and ensuring that an adequate depth of cover over the pipeline was maintained so as not to interfere with future road or rail crossings.

Johannes Prinz von Thurn und Taxis supported the application but expressed concern respecting the "piecemeal" development of pipelines in the area. His counsel further questioned the jurisidictional aspects of the hearing, suggesting that the jurisdiction of the Board had been effectively fettered by Government policy relating to a possible pipeline corridor in the area.

5 THE ISSUES

Although a variety of matters were discussed during the hearing, the Board considers the major issues to be:

- need for the NUL pipeline,
- the pipeline route,
- right of way matters,
- environmental and agricultural impacts caused by the pipeline,
- special problems related to the possible corridor, and
- acquisition of interest in lands.

6 NEED FOR THE NUL PIPELINE

6.1 Supply of Gas for the Celanese Plant

The applicant stated that the pipeline was needed by July 1982 to supply gas to a new methanol facility, now under construction at the Celanese plant. The natural gas is to be purchased by Celanese from Nova, An Alberta Corporation (Nova) and others, and transported through sections of NUL's existing facilities via the proposed pipeline to Celanese.

Celanese requires gas at a high pressure (3800 kPa). In order to provide this pressure the applicant considered two basic alternatives which would supply the forecast Celanese demand of 3100 10^3 m^3/day. The first of these would be to provide compression at the Celanese plant and augment the existing NUL system to provide the extra volumes. The cumulative 20-year cost of providing a 6640 kW compressor to meet this need was estimated by NUL to be $35.9 million (1981 dollars). Although this would cause minimal effect on the land surface, NUL concluded that a single compressor-backed supply would not provide sufficiently reliable service.

The second alternative to provide gas to Celanese would be by a newly constructed pipeline such as the one proposed. A variation of this which would satisfy only the requirements of the Celanese plant would be construction of a 406-mm diameter pipeline to connect with the existing NUL system at the Inland Wye (Figure 1). This pipeline would follow the same route as the 762/610-mm line currently applied for. The cumulative 20-year cost of providing this 406-mm pipeline was estimated by NUL to be some $11.6 million (1982 dollars). Compared to the compression alternative, this would have a major effect on the land surface during construction, but would provide a more reliable source to Celanese.

With regard to the comparative reliabilities of compressors and pipelines, the applicant noted that compression facilities require periodic shutdowns for maintenance purposes, and the in-service failure of a single unit would have serious consequences on the plant operation. It said that although it has several compressors within its existing operation, these were invariably installed in situations where sufficient back-up gas supplies were available in the event of a compressor outage. The applicant further contended that the pipeline alternative had the advantage of being able to remain in service indefinitely without periodic shutdown; moreover the sources of upstream gas supplies from Nova were sufficiently diverse to preclude loss of gas supply resulting from any single compressor outage on Nova's system.

Drs. Shirvell and Simmons questioned the applicant about alternative gas supplies available to Celanese from outside the NUL system. The applicant contended that, as a utility, it had merely responded to a request for gas supply from Celanese. Neither Celanese nor any of the interveners provided specific evidence about the provision of gas from other sources. Celanese did, however, confirm that it had contracted with NUL to transport gas to the new methanol plant, and that it fully supported NUL's application.

6.2 Supply of Gas for the Edmonton and Fort Saskatchewan Area

Although the need to supply gas to the Celanese plant was an immediate requirement, the applicant identified a further need to provide additional gas in the future to the Edmonton demand area. The additional supplies would be for gas to satisfy the peak demand.[5] The applicant forecast that the peak day demand for the Edmonton area, not

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5 Peak demand is the instantaneous maximum requirement for gas which occurs over a relatively short period of time. Thus the peak day demand is the amount of gas required on the day of heaviest consumption in a given year.

including the requirements for the Celanese plant, would exceed the capacity of the existing transmission system by the winter of 1983-84. The shortfall would be some 4700 10^3 m^3/day, and would be caused primarily by the forecast increase in demand for proposed industrial plants in the Fort Saskatchewan area. Furthermore, this shortfall in gas supplies was forecast by NUL to increase to some 15 400 10^3 m^3/day by the winter of 1986-87.

In response to questioning from Drs. Shirvell and Simmons, the applicant noted that the majority of the proposed plants in the Fort Saskatchewan area were under construction, and were almost certain to be sources of gas demand in the near future.

The applicant noted that the ability for the NUL supply system to meet the seasonal residential and commercial peak gas demand would be seriously affected by the addition of future industrial plants. Although the entire needs of any particular plant might not be supplied through a given pipeline, the cumulative effect of the added base loads[6] is to substantially erode the peaking capacity of the integrated transmission system. As each base load is added, the overall supply/demand pattern of the transmission system changes, as does the role of each pipeline segment.

NUL stated that a critical aspect of determining the need for a future pipeline facility is the ability to accurately forecast future gas demand. As a result of questioning, evidence was presented about two basic types of gas demand; the annual sales[7] and the peak day. Although the two types of demand are linked by an indirect relationship, the most critical demand which a pipeline system must satisfy is the peak day. In the NUL system, the peak day demand generally occurs during a period of extreme winter cold, and is closely related to the outside air temperature.

In order to forecast what this peak day demand might be in future years, the applicant first estimated the projected population growth for the Edmonton/Fort Saskatchewan demand area. It then apportioned this growth into a projected share of residential and commercial customers for natural gas. A specific gas consumption per customer was then applied to determine the overall peak residential and commercial demands.

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6 Base loads are gas demands which do not fluctuate significantly during the year and are normally independent of outside air temperature.

7 Annual sales is the total quantity of gas sold in a given year. It represents the amount of gas which the supplier must make available from all sources for customers to consume at a variable rate throughout the year.

The applicant noted that the specific consumption per customer has been dropping in recent years, due in part to energy conservation resulting from higher gas costs which is reflected in improved insulation and more efficient heating systems. In fact, the average peak day demand per customer has dropped by some nine per cent in the last five years, to the current level of 3.6 gigajoules/day. This figure was projected over the forecast period to give an estimate of peak day demand for space-heating type customers.

Additionally, the applicant projected the peak day demand from its industrial customers. The nature of this demand is more constant because it is dependent largely on a process load, and is independent of air temperature.

In order to arrive at the overall projected peak day demand, the applicant summated the space heating and industrial loads. NUL noted that in its projections the proportion of industrial base load fluctuated due to irregular growth in the two sectors. With regard to the reliability and accuracy of its forecasting methods, the applicant stated that the forecasts are reviewed each year with respect to the actual peak day demand, and relative to the air temperature on the peak day.

The applicant discussed several alternatives which could meet the forecast demand. With one exception, the looping of or adding compression to existing pipelines was unable to meet the demand. This exception, the looping of the Homeglen-Rimbey pipeline, was the most costly of the alternatives examined. The cumulative 20-year present value cost would be some $149.6 million (1982 dollars).

A further alternative which would meet the forecast demand was to construct a new pipeline from the west to Edmonton for a cumulative 20-year present value cost of $97.5 million (1982 dollars).

The alternative preferred by NUL, to supply both the Celanese and Edmonton/Fort Saskatchewan demand, was to develop salt cavern storage in the Fort Saskatchewan area, and to connect this storage to the existing NUL transmission system via pipeline. In order to accomplish this connection, the route of the pipeline would follow the routing of the present application, and would be of 762/610 mm-diameter. The cumulative present value cost of this alternative would be some $57.6 million (1982 dollars).

6.3 The Interveners' Views

Drs. Shirvell and Simmons questioned the need for the proposed pipeline but did not present evidence related thereto.

6.4 The Board's Views

The Board believes that the applicant has demonstrated a need to provide a supply of natural gas to the Celanese plant. The Board notes that a pipeline can be constructed for a cost which is less than one-third the cost of providing on-site compression, and agrees with the applicant that a pipeline connected to an integrated supply system will provide a more secure service.

With respect to the possibility of providing gas to the Celanese plant from an alternative supplier, the Board believes that NUL was under no obligation to search out such competition. It considers that Celanese is sufficiently astute to have carried out any needed review of alternatives before it requested the gas supply from NUL. Moreover, the Board believes that the widespread advertising of the application is sufficient notice to enable any competing suppliers to advise the Board of any interest in supplying gas to Celanese.

In addition to the need for a supply of gas to the Celanese plant, the Board notes the applicant's contention that its existing transmission system will not be able to supply the future needs of the Edmonton and Fort Saskatchewan areas. The Board further notes that, depending on the extent of industrial load growth, there will be a shortfall in peak gas supplies sometime between the fall of 1983 and spring of 1985. With respect to the method of forecasting peak day demands, the Board recognizes that many assumptions and predictions must be made, and that NUL's historical information must be considered to make a final judgement on the requirements for gas supplies. The Board believes that it is significant that NUL's previous forecasts were only some three per cent lower than the actual peak demand in the 1981-82 winter. Recognizing the severe and unpredictable nature of Alberta's climate, the Board believes that NUL's requirement that peak gas supplies be sufficient for a -40°C day is prudent.

For the above reasons, the Board generally agrees with the applicant's forecasts and concludes that there will be a need for additional peaking gas supplies for the Edmonton and Fort Saskatchewan areas within the next few years.

The Board notes that NUL undertook several studies to review alternatives which would wholly or partially meet the projected shortfall in gas supplies. It is clear that from a cost of service standpoint, the most justifiable proposal is to develop salt cavern storage and to connect this storage to the existing NUL transmission system via a pipeline. The estimated cost of this proposal, at $57.6 million (1982 dollars) is clearly preferable to the nearest cost alternative of $97.5 million (1982 dollars) for another new pipeline to the west of the city. Additionally, the Board notes that the two alternatives to the salt cavern storage and the applied-for pipeline would still require

considerable lengths of pipeline to be installed, quite likely longer than the current application, with perhaps a greater impact on existing and future land surface uses.

The Board is aware that NUL has not yet applied for and does not have approval for the development of the salt cavern storage in the Fort Saskatchewan area, and notes that a failure to obtain such an approval could affect the overall economics of the current application. However, the Board believes that in such an event the applied-for line could still be utilized to provide supplies for the Celanese plant and, depending on the economics of upstream looping, for all or a portion of the peak day demand of the City of Edmonton.

In summary, the Board is satisfied that there is a need for the pipeline applied for in that it can provide both a reliable source of supply for the Celanese plant and a means of meeting the peak day gas demands of the Edmonton and Fort Saskatchewan areas.

7 THE PIPELINE ROUTE

7.1 The Applicant's Views

NUL stated that its proposed route was the logical choice, since the majority of it parallelled existing pipeline rights of way and the CPR railway. Alternative routes had been investigated but ruled out for a variety of reasons. For example, parallelling existing NUL facilities into Edmonton was not practical because of subdivision development along Highway 16, and the increased length could not be justified. Another alternative, that of following Shell's proposed lines from the Scotford refinery was also eliminated because of a previous Board decision.[2] In response to a request from Dr. Shirvell to re-route the line around his property, the applicant had two concerns. The first involved the severance of additional lands and the second was increased project costs. Asked to explain these points, NUL pointed out that setback distances from roads could place the pipeline some 100 feet (30 metres) into the adjoining quarter section. It also stated that because of the additonal length involved, the extra costs would amount to approximately $35,000.

7.2 The Interveners' Views

Both Drs. Shirvell and Simmons objected to the placement of pipelines across top-quality farmland, contending that it would result in a severe reduction in soil fertility, and could reduce crop yields as much as 40 per cent in the first year. Dr. Shirvell also stated that the pipeline would have a severe negative impact on the future residential use of his

corner property, and cited figures to show that if NUL was granted the right of way being asked for, only 33 per cent of the corner would remain for the highest and best use of his land.

Dr. Shirvell maintained that re-routing the pipeline around his property would be in the public interest, would only add 44 metres to the total pipeline length, and would eliminate the conflict with residential construction on his property. He said that the adjacent landowners had no objection to the pipeline being re-routed across their land, but confirmed that their agreement had been verbal only and that he had nothing in writing. He further stated that he had not discussed setback distances or potential land-use sterilization resulting from such setbacks.

Figure 3 shows the proposed route in the vicinity of the properties of Drs. Shirvell and Simmons and illustrates the matters raised by them and NUL's requested routing.

7.3 The Board's Views

In terms of the general route, the Board believes that the applicant has selected the alternative that best utilizes existing linear disturbances. By following section lines, pipeline rights of way and a major railway, it appears to the Board that land fragmentation has been kept to a minimum. The Board also believes that the route provides reasonable access for future pipelines planned by the company.

Concerning a re-route around Dr. Shirvell's property, the Board notes that the landowners that would be affected by such a move were not present at the hearing, nor was any written evidence presented by them. The Board further notes that present legislation would require a 30-metre setback from roads which could only be reduced under special circumstances. This would place a re-routed pipeline a considerable distance into landowners' property, and in effect establish a new pipeline alignment (see Figure 3). If future pipelines were to follow this general route, presumably they would follow the realignment, thus disrupting more lands than the proposed route would. For all of these reasons, and because Dr. Shirvell's property is not totally unique, the Board does not believe it would be in the public interest to re-route the pipeline around the property. The Board considers the same reasoning to equally apply to re-routing around Dr. Simmons' property.

8 RIGHT OF WAY MATTERS

8.1 The Applicant's Views

The applicant proposed to install its pipeline 7.5 metres from the dual AEC pipelines within the proposed corridor, and 5 metres from the boundary of the AEC right of way outside the proposed corridor. Where it parallelled its

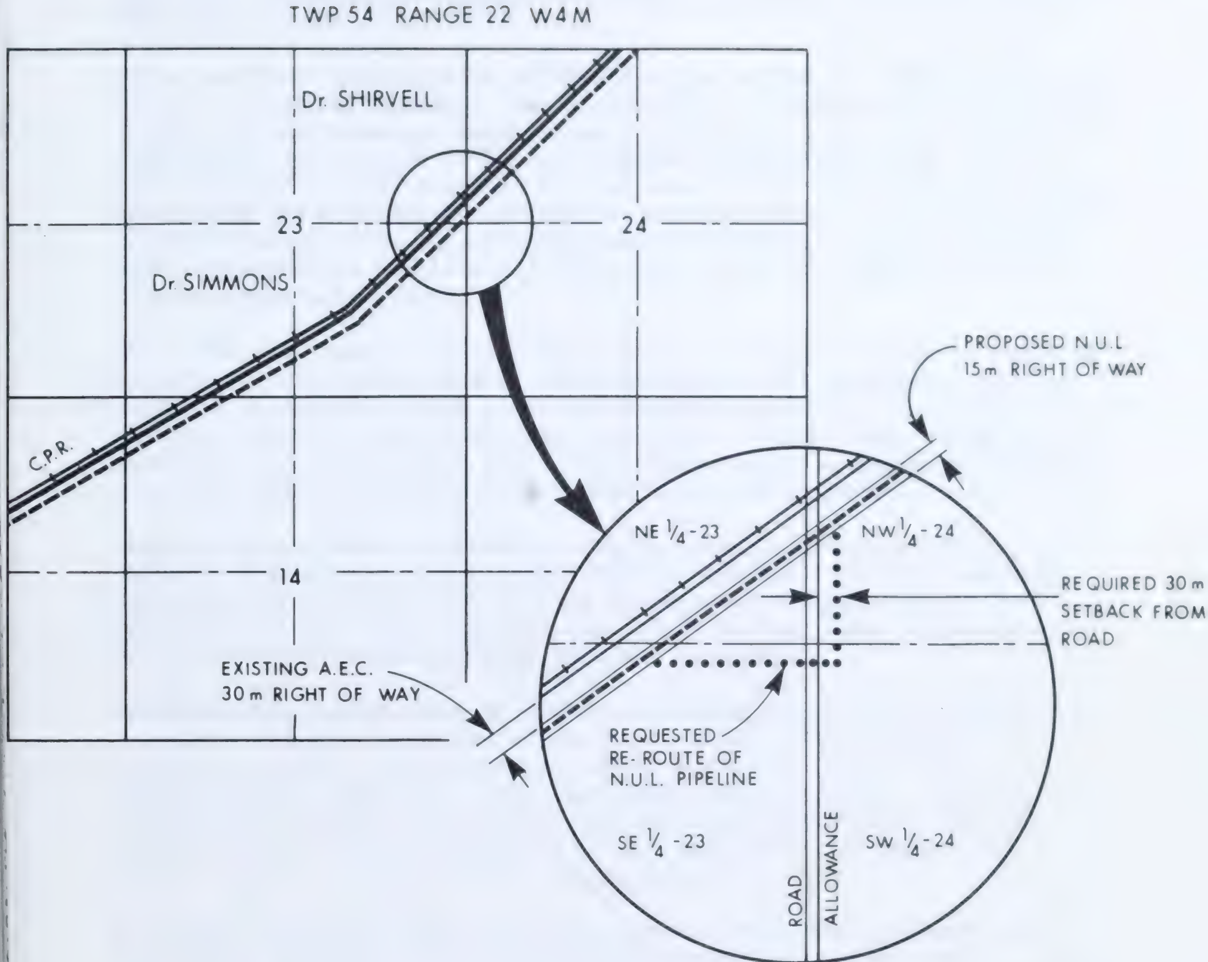

FIGURE 3 PROPOSED PIPELINE RE-ROUTING AROUND NE 1/4-23-54-22W4

own lines from the Inland Wye takeoff, and where new NUL right of way was required, the pipeline would be appropriately placed within the available NUL right of way.

NUL stated that the position of its pipeline within its right of way, and relative to other pipelines, was chosen after considering a number of factors of approximately equal concern. Generally, it wished to acquire sufficient right of way to provide for the installation of a first pipeline, and for the possible future installation of a parallel pipeline should that be necessary. It would then place the first pipeline, using conventional pipeline construction methods developed over the years, in such a position as to allow for the construction of a future pipeline using similar methods.

NUL would also want to ensure that, where its pipeline would be installed adjacent to existing pipelines owned by others, its position within the right of way would be such as to preclude the necessity of working over or near any other pipeline with heavy equipment. Under questioning, the applicant stated that such activities could result in damage to existing pipelines, particularly in wet, poorly consolidated ground.

The applicant also stated that it was necessary to acquire sufficient space to allow for a proper restoration of the right of way following construction; however, such working space could normally be acquired temporarily outside the right of way. This working space could again be affected by the existence of adjacent pipelines.

Two remaining factors were of particular concern in situations where pipelines would be installed closer than normal, such as within the proposed corridor. NUL noted that there would be a need to make connections of some type to the gas transmission pipeline, and such connections were of a complex nature requiring considerable physical space. Under questioning, the applicant was unable to predict the location of any of these future connections.

A further aspect of pipeline spacing identified by the applicant was the necessity to space pipelines at a distance to preclude the possibility of the exposure and damage of nearby pipelines by the blast effects of a possible rupture of the gas line. Under cross examination, the applicant admitted that no evidence of actual cases of pipeline damage was available to substantiate this theory. The applicant also noted that increased spacing was necessary to accomodate the installation of "big-inch"[8] pipelines, although this was not quantified by any evidence presented during the hearing.

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8 "Big-inch" pipelines are those requiring the larger type of construction machinery for their installation. The term is generally applied to pipelines larger than 323-mm OD.

In response to the Schroter's intervention, NUL stated that the depth of the proposed pipeline would be adequate for future rail spur lines, because the raising of the track bed for a proposed rail line would very likely bring the depth of cover to at least the 1.2 metres required by the Canadian Standard for Gas Pipeline Systems.

8.2 The Interveners' Views

Although Dr. Shirvell preferred re-routing the pipeline around his property, he stated that if the Board deemed this not to be a viable alternative, then NUL should be required to use part of the existing AEC right of way across his and Dr. Simmons' properties. He claimed that the Board had granted the 30-metre right of way to AEC on the understanding that the unused portion would be shared in order to reduce the impact on the landowners' use of their land. In support of this claim, Dr. Shirvell cited figures to show that about 22 metres of right of way adjacent to the proposed NUL right of way were available for use, and that NUL's pipeline could be placed as close as 7.5 metres from the AEC lines, still leaving approximately 15 metres of unused right of way.

A further point made by Drs. Shirvell and Simmons related to the width of right of way being requested by NUL for its pipeline outside of the proposed northeast Edmonton pipeline corridor. Dr. Shirvell argued that 15 metres was considerably more than the company needed as permanent right of way, and that it should be restricted to 5 metres. He stated that he had no objection to the company requesting temporary working space beyond the 5-metre width, and that he was prepared to make such space available for a short period of time.

The spokesman for Schroter Enterprises, Richard Schroter, stated that the 15-metre width of right of way being requested by NUL across the Schroter Enterprises land was excessive. In addition, he claimed that when he granted AEC its 30-metre right of way width, he understood that it was going to accommodate future pipelines, and that at present there were only two small lines in the right of way. Schroter Enterprises was concerned about the route through a deep ravine on its land, and the effect a second, wider right of way would have on the large trees that were growing there, since AEC had already cleared the full 30-metre right of way width through the ravine. Under questioning by NUL counsel, Schroter Enterprises stated that its first choice was for NUL to share the AEC right of way, but that it would be prepared to accept a 10-metre right of way width and grant additional working space to the company. The intervener also elicited a commitment from NUL that the company would endeavour to stay within the narrower right of way without additional working space, and possibly use part of the AEC right of way for working space.

AEC was opposed to placing NUL's pipeline in its right of way, claiming that its plans for additional pipelines would fully utilize the remain-

ing space. AEC also pointed out that allowing different companies into its right of way would result in additional crossings that could increase the risk of accidents.

The Schroters were concerned about the suitability of the proposed 1-metre depth of cover, in the event that a future industrial subdivision required a rail spur line to cross the pipeline. Another intervener, Schroter Enterprises, was concerned that the 1-metre depth of cover was insufficient to provide protection from heavy farm equipment since on occasion, in wet conditions its machinery had settled 1 metre into the ground.

8.3 The Board's Views

The Board believes that the principle of sharing rights of way should be followed whenever the opportunity arises. In view of the fact that the Board suggested consideration of joint usage when it first approved the unusually large AEC right of way width, the Board is disappointed that the applicant did not present firm evidence to show that it had tried to share the right of way with AEC, and that it did not better document the reasons for being unable to do so. In the absence of such information, and without specific up-to-date knowledge of AEC's future pipeline plans for its right of way, the Board must rely on the statements made by AEC at the subject hearing, that it will require its total right of way. On this basis the Board concludes that it would not be proper to require NUL to share the AEC right of way. It does, however, wish to emphasize that the remaining AEC right of way (approximately 22 metres) will be considered by the Board for use by future applicants unless specific evidence is presented to show that such use is not reasonable or in the public interest.

The Board is of the opinion that the interveners were justified in requesting a narrower NUL right of way through their property. The Board shares Dr. Shirvell's concerns about the reduced area of land for potential residential use resulting from wide pipeline rights of way across his property, and considers that a 5-metre wide right of way with temporary working space on each side should be adequate to meet the needs of NUL.

Regarding the ravine crossing on Schroter Enterprises' property, the Board agrees that a minimum right of way width and minimum clearing of trees and bush should be maintained through the area. Accordingly, it believes that a 5-metre wide right of way width with working space over the unused portion of the AEC right of way would be sufficient. If NUL finds that a wider right of way or clearing of trees and bush for working space is needed for construction across this property due to the slope of the ravine, the Board would consider a request from the company to this effect. Approval would only be given if the Board could verify the absolute need for the additional width by having its field staff conduct an examination of the site. Consultation with the landowner would also take place.

Concerning the remaining portion of the applicant's proposed route parallelling the AEC right of way outside the possible northeast Edmonton corridor, the Board is of the opinion that the applicant did not show sufficient need for a second future pipeline, and the subsequent necessity for a wider right of way. The Board believes, therefore, that a 5-metre wide right of way adjacent to the AEC right of way, as was earlier stipulated for Dr. Shirvell's and Schroter Enterprises' properties, would provide sufficient space for the NUL pipeline, and would be consistent with keeping permanent right of way widths to a practical minumum. Throughout this section of the proposed line the Board believes that the pipeline should be placed along the centre of the right of way.

For the remainder of NUL's proposed route where it is neither in the possible northeast Edmonton corridor, nor parallel to the AEC right of way, the Board notes from documentation that a portion of it will be in an existing NUL right of way. For that portion which is not, the Board is of the opinion that a 10-metre wide right of way would be sufficient to meet NUL's construction needs. The additional width of right of way would be justified because there is not an adjacent existing right of way to use as working space. The Board notes that no landowners commented on the right of way width along this section of the proposed line.

When pipelines are closely spaced such as in the possible corridor, the Board notes that there may be additional factors that determine spacing. For example, the Board agrees that working above or near other operating pipelines should be avoided wherever possible to reduce the chance of accidental damage. The applicant did not, however, present any evidence which properly defined the nature or probability of this risk. The Board believes that there may be precautions such as the placing of protective materials over the pipeline, or supervision by the existing pipeline owner, which could substantially reduce any existing risk. The Board also believes that there may be alternative methods and equipment available which would reduce the necessity of working over existing pipelines.

The Board recognizes the need for making connections to the proposed pipeline in the future, and accepts that some space will be required for these connections. However, the Board believes that the practice of leaving sufficient space for such connections along the entire route is not necessary, particularly within restricted areas such as the possible corridor. In such areas, given a closer pipeline spacing, it would be more desirable to acquire working space as and when needed. The Board further believes that different design alternatives to the conventional connection methods may also reduce the permanent area required.

In regard to the matter of secondary pipeline damage resulting from a major pipeline rupture, the Board notes that although NUL may prefer to place its line as far as possible from any other pipelines, no clear evidence was presented to justify this. Indeed, the "Joint Technical Report on a Northeast Edmonton Pipeline Corridor", presented as evidence by the applicant, notes that the authors were unable to determine any incidents of secondary ruptures of adjacent pipelines from direct mechanical impact due to blast effects. The Board is therefore of the opinion that this factor is insufficient by itself to justify any particular pipeline spacing.

While the foregoing factors do not strongly favour a specific safe distance between pipelines, the Board believes that construction practices for installation of a large diameter gas pipeline require a somewhat greater than normal spacing. Accordingly, the Board is prepared to accept the 7.5-metre spacing and 10-metre wide right of way requested by the applicant for its pipeline in the possible corridor. The Board notes that this is wider than the right of way prescribed for the portion of the route which parallels the AEC right of way but which is outside the possible corridor. The reason for this is because within the possible corridor the neighbouring lines are immediately adjacent, whereas outside of the possible corridor they are 22 metres further away than the edge of the right of way.

In summary, if the Board issues a permit to NUL, it would prescribe:

(i) placing the proposed pipeline within the NUL right of way where available along the route,

(ii) a new 10-metre right of way for that portion of the proposed pipeline route not adjacent to existing pipelines,

(iii) a new 5-metre right of way adjacent to the AEC right of way outside of the possible corridor, with the pipeline located in the centre, and

(iv) a 10-metre right of way and 7.5-metre spacing from the existing AEC pipelines, within the possible corridor (from approximately Lsd 2-31-53-22 W4 to Lsd 3-21-53-23 W4).

With respect to the Schroters' request for the extra depth of burial in the event of a future rail spur crossing, the Board agrees with NUL that the raising of the track bed for any future crossing would result in adequate cover. Also, the Board does not agree with Schroter Enterprises that 1-metre cover would be insufficient to accomodate heavy farm equipment. Consequently, the Board would not require any extra depth of burial beyond that proposed by NUL.

9 ENVIRONMENTAL IMPACTS

9.1 The Applicant's Views

The applicant stated that it had submitted the proposed route to Alberta Culture and had received a letter from that agency approving its methods and procedures to avoid damaging historical and archaeological resources. In addition, an environmental protection plan had been prepared for NUL by an independent soils consultant, and the applicant confirmed that it would follow wherever possible the recommendations contained in the report. Questioned as to when it might not be possible to follow all the recommendations, NUL replied that wet weather and tight deadlines might cause some unavoidable deviations in the procedures.

9.2 The Interveners' Views

Some of the interveners questioned items in the environmental protection plan concerning depth of cover under streams, ravine crossings, and land disturbance. Counsel for the Schroters was particularly concerned about the depth of cover across his client's land. Counsel for Drs. Shirvell and Simmons was apprehensive about environmental damage occurring because of lack of supervision during construction.

9.3 The Board's Views

The Board is satisfied that the proposal is acceptable from an environmental viewpoint. The Board notes that the applicant stated it would normally follow all the recommendations contained in the consultant's environmental protection plan, and that it would have no objection to an undertaking whereby it would inform the Board of any intended departures from the recommendations. The Board considers this to be a valid permit condition should one be granted.

10 AGRICULTURAL IMPACTS

10.1 The Applicant's Views

The applicant outlined in detail what it considered to be proper topsoil and spoil bank handling procedures during pipeline construction, and stated that in its judgement, the problem of mixing could be minimized. The preferred method was to pile topsoil on topsoil, and spoil material on subsoil, and this procedure could be followed provided there was adequate working space on either side of the pipe ditch. Notwithstanding some of the working space limitations that the proposed corridor might present, NUL stated that it was prepared to undertake any procedures that would maximize conservation of the topsoil, including any or all necessary stripping of topsoil under the spoil bank.

In response to questioning, NUL stated that it would take into consideration the concerns of farm operators, and would do its utmost to avoid interference with farming operations. Construction would be planned around seeding operations, but if timing problems could not be avoided, the farmer would be compensated for any crop loss.

NUL also outlined a number of items concerning agricultural matters that the three companies, AEC, NUL, and Shell had worked out together as an informal management group of the proposed pipeline corridor (also see section 12). These dealt mainly with topsoil stripping over their respective rights of way, and possible overlap of soil reclamation procedures caused by construction schedules. During the hearing, the applicant stated that it would agree to strip topsoil from beneath the spoil pile if requested by a landowner.

10.2 The Interveners' Views

Drs. Shirvell and Simmons contended that the soil classification on their farm land was the highest in Canada, and that the growing of feed grains had been very productive. They believed that the pipeline would adversely affect soil fertility, and that crop yields could be reduced for at least four years. This estimate was based on an Agriculture Canada report.

Dr. Shirvell claimed that the tenant farming his small triangle of land no longer felt that it was viable for agricultural use, and that access problems for farm equipment had made the operation uneconomical. As a result, Dr. Shirvell said that it was difficult to find anyone willing to farm the land. On being questioned about the crop yield from this parcel of land, Dr. Shirvell stated that he did not know what it was, since he was not farming it himself.

Dr. Shirvell also cited some soil conservation problems that he found with the first pipeline through his property. He maintained that proper methods had not been followed, and that some soil mixing had occurred. With regard to the applicant's report on soil conservation methods during construction, Dr. Shirvell was in full agreement with the consultant's recommendation that topsoil should be placed on topsoil, and spoil on top of subsoil. He disagreed, however, that both piles should be on the same side of the trench, maintaining that mixing could be avoided only if the topsoil and spoil bank were on opposite sides of the trench. Dr. Shirvell also pointed out that the diagrams in the consultant's report and the applicant's own diagrams for topsoil and spoil bank locations appeared to be at variance with one another.

AEC stated that it would allow NUL to stockpile material over its right of way during construction of the pipeline, provided that there was prior consultation on construction techniques such that AEC's line would not be harmed in any way.

10.3 The Board's Views

The Board notes NUL's commitment to undertake all procedures necessary for topsoil conservation, and believes that if the general concept of placing topsoil on topsoil and spoil bank on subsoil is followed, such conservation is possible. The Board also believes that the applicant can avoid interference with farming operations during pipeline construction by working closely with the particular landowners involved.

Concerning Dr. Shirvell's statement that drastically reduced crop yields over a period of four years could result from pipeline construction, the Board notes that this statement was not based on any information specific to Dr. Shirvell's property nor was it supported with meaningful evidence. The Board notes that any losses would be compensated for, and is of the opinion that good soil conservation procedures can keep such losses to a minimum.

The Board understands Dr. Shirvell's concerns about his small piece of property being successively divided by additional pipeline rights of way but believes that this should not interfere with the full use of his land for agricultural purposes. There are innumerable precedents in the Province of successful farming operations over pipelines, and the Board believes that proper arrangements can be worked out with the pipeline companies involved to restore proper access to the property for farm machinery.

It appears to the Board that the goal of good soil conservation can be successfully realized if the recommendations outlined in the applicant's environmental protection plan are followed. The Board recommends that close monitoring during pipeline construction be provided by the applicant, and that liaison with local Land Reclamation Council Officers and the landowners involved be maintained throughout the project.

11 SPECIAL PROBLEMS RELATED TO THE POSSIBLE CORRIDOR

11.1 The Applicant's Views

The applicant stated that because of spacing and other concerns that have come up in the time that the potential corridor has been under consideration, three companies (AEC, Shell, and NUL) had met a number of times as an informal corridor management group. Matters such as topsoil stripping off adjacent rights of way, working space over operating lines, and timing of reclamation procedures were discussed, and the participants believed that these issues could and should be worked out by the participants themselves.

Notwithstanding the discussions that have taken place among the companies that will be operating in any future corridor, NUL pointed

out that a true management group has yet to be formed. It was anticipated that such a group could be in place and available for a management role if the corridor was officially established. The areas of concern that would be addressed at that time would primarily involve the inspection and safe guarding of new facilities during the construction and operational phases, and a technical group would be formed to advise the management committee on specific individual issues.

11.2 The Interveners' Views

Counsel for Shell suggested that a permanent principle should be adopted in the potential corridor requiring all pipelines to be located in the centre of their respective rights of way. This would ensure that each succeeding pipeline would not require an excess right of way width in order to maintain a safe spacing distance.

The matter of Board jurisdiction in the potential pipeline corridor was raised by counsel for Johannes Prinz von Thurn und Taxis, who stated that such jurisdiction had been effectively fettered by government policy. He said that affected landowners in the corridor did not know which government agency or legislation they were dealing with, and that the Board's jurisdiction was limited by the existence of a corridor with an undefined legal framework. Since the Minister of the Environment reserved the right to impose such a framework at some later date, it left landowners negotiating at the present time in a very unfair position. He believed that the onus was on the Alberta Government to resolve the issue as quickly as possible in order not to hamper future development by uncertain jurisdictional issues. Notwithstanding this, counsel for Johannes Prinz von Thurn und Taxis stated that he had no objection to the granting of the application before the Board.

11.3 The Board's Views

The Board believes that the issues raised concerning a permanent corridor management group reinforces its earlier observations that such a group is an essential part of corridor planning and administration. It further believes that if a corridor is declared it should be managed by a consortium of participants who would deal with all matters affecting the safe construction and operation of pipelines within it.

The Board is also of the opinion that its earlier views concerning land acquisition within the possible corridor have been confirmed by current events. Acquisition of the total corridor as soon as possible is strongly recommended, whether such acquisition be by industry or government. It would avoid piecemeal right of way negotiations each time a new pipeline is proposed within the corridor, and could avoid costly hearings in the future. It would also be fairer to the present landowners.

Regarding the jurisdictional issue raised by Johannes Prinz von Thurn und Taxis, the Board considers that it has adequate authority under the Pipeline Act to consider the routing of any proposed pipeline.

12 ACQUISTION OF INTEREST IN LANDS

12.1 The Intervener's Views

Dr. Shirvell requested that if the Board grants a permit for the proposed pipeline, it should stipulate that NUL must acquire the interest in land by negotiation with the owners as allowed for under section 11(2) of the Pipeline Act. The intervener stated that this would be justified because the pipeline would ruin his current farming operations and future subdivision possibilities. It was the opinion of the intervener that there was no clear necessity for the proposed pipeline, and that the sole reason for installing the pipeline at this time was to make a profit. This, the intervener contended, was not in the public interest and therefore the applicant should not be able to acquire the interest in the land by proceeding under the Surface Rights Act. The intervener stated that if NUL was going to make a substantial profit from the pipeline, he should be allowed to negotiate for an equitable share of that profit.

12.2 The Board's Views

The Board believes that section 11(2) of the Pipeline Act should only be used by the Board where it has been demonstrated by a party suggesting that the section be invoked that a unique situation exists. The Board sees no such situation in this case. The Board believes the proposed line is needed to supply gas to the Edmonton area and is thus in the public interest. Accordingly, the Board is not prepared to invoke the provisions of section 11(2) of the Pipeline Act as requested by Dr. Shirvell.

13 DECISION

The Board, on the basis of its views set out earlier in this report, approves Application 820083 of Northwestern Utilities Limited for its proposed pipeline from Lsd 1-4-55-20 W4M to Lsd 3-21-53-23 W4M. The

appropriate permit to construct will be issued in due course, subject to the approvals of the Minister of the Environment in matters of the environment and Restricted Development Areas.

ISSUED at Calgary, Alberta on 7 June 1982.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

V. E. Bohme

V. E. Bohme, P.Eng.
Board Member

E. J. Morin

E. J. Morin, P.Eng.
Acting Board Member

APPENDIX

Principal and Representatives (Abbreviations used in Report)	Witnesses
Northwestern Utilities Limited (NUL) D. R. Thomas	E. F. Provost, P.Eng. G. K. Munk, P. Eng. R. Armstrong, P.Eng. Dr. R. R. Cairns L. G. Wattie T. W. Peters
Alberta Energy Company Ltd. (AEC) B. Zalmanowitz	
Celanese Canada Inc. (Celanese) Eric Nicholson	
Johannes Prinz von Thurn und Taxis W. Rowe	
R & M Schroter Enterprises Ltd. (Schroter Enterprises) W.K.J. Mis	Richard Schroter
June & Allan Schroter (The Schroters) H. Sniderman	
Shell Canada Limited (Shell) R. M. Curtis	
Dr. C. S. Shirvell Dr. H. Simmons D. Carter	Dr. C. S. Shirvell Dr. H. Simmons
Energy Resources Conservation Board staff (Board staff) K. F. Miller R. J. Allman, P.Eng. J. Owen	

Mr. Albert Komant tendered a submission but did not appear at the hearing.

Alberta Environment, represented by Mr. R. Dyer, filed a letter in accordance with section 26 of the Board's Rules of Practice.

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

GULF CANADA RESOURCES INC.
APPLICATION FOR A WELL LICENCE TO DRILL AN EXPLORATORY WELL IN THE MILLARVILLE AREA

Decision 82-23
Application 820283

1 INTRODUCTION

1.1 The Application and Hearing

Gulf Canada Resources Inc. applied to the Energy Resources Conservation Board (the Board) for a licence to drill the proposed well, GULF ET AL MILLARVILLE 6-32-22-4. The well would be directionally drilled from a surface location in legal subdivision 14, section 29, township 22, range 4, west of the 5th meridian.

A public hearing to consider the application was held on 13 May 1982, in Calgary, Alberta, with G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and E. R. Brushett, P.Eng., sitting.

A number of the residents of Rusticana Estates, Echo Hill, and the surrounding area, represented by Mrs, Dorothy Martin, filed an objection to the drilling of a well. An intervention against the well was also filed by D.J.E. Consulting, on behalf of the Canadian Wildlife Federation.

Mrs. Mary C. Galeski filed an intervention, but did not appear at the hearing.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Gulf Canada Resources Inc. (Gulf) J. E. Nozick	A. E. Wallace, P.Eng. A. G. Van Dyck, P.Geol. R. D. Hennig
Rusticana Estates, Echo Hill and the surrounding area (Local Residents Group) D. A. Martin	D. A. Martin

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations used in Report)	Witnesses
Canadian Wildlife Federation (Wildlife Federation) D. J. Evans of D.J.E. Consulting	
Energy Resources Conservation Board staff K. F. Miller J. R. Nichol, P.Eng. W. G. Remmer, P.Eng. S. A. Martin, P.Eng.	

1.2 Preliminary Matter

Gulf opened the hearing with a request that the Wildlife Federation not be heard at the hearing because: (1) it did not have a bona fide interest in the application as required by the Board's Rules of Practice, and (2) it did not represent the general public as a whole. The Wildlife Federation responded to this request by stating that, since the drilling was to take place on public land, it had the right, as a public entity concerned with wildlife, to intervene. The Board ruled that the Wildlife Federation would be accepted as an intervener provided that its involvement was limited to cross-examination and argument, as was stipulated in its filed intervention, and that matters pertaining to pipelining and gas processing would not be addressed.

The Board stressed that, as the proposed well is exploratory in nature, it is not possible, nor practical, that detailed pipeline and processing plans be included with the well licence application. The Board emphasized that it was taking this position completely without prejudice to any future disposition of related pipeline and gas processing applications that it may receive if a well licence was granted and a well successfully drilled. In this regard, the Board stated that the applicant takes a risk with respect to the disposition of any related future applications to the Board.

2 CONSIDERATION OF THE APPLICATION

2.1 Views of Gulf

In its application, Gulf stated that it had the right to drill for oil and gas in all of section 32, township 22, range 4, west of the 5th meridian, down to and including the Rundle formation. The well would be drilled on 100 per cent Gulf Crown lease land which has a lease

expiry date of 23 August 1983. Should the proposed well be successful, a second well to the southeast would be required for pool development, and would have to be tested prior to the lease expiry date. Gulf indicated that the well would test a faulted Mississippian structure and that any gas encountered would have a maximum hydrogen sulphide (H_2S) content of some 4.3 per cent. Gulf stated that the exploratory wildcat well has a 25 per cent or less chance of success and, should the well be productive, expects a total calculated structure recoverable reserve of some 4.8 billion cubic metres.

Gulf estimated that the well would take 90 days to drill, and would prefer to drill during the summer, when weather conditions are more favourable, with respect to both safety and noise levels. Also, access would be better in summer, and evacuation of the area, in the unlikely event it were to become necessary, would be easier. Gulf also mentioned that the population close to major urban centres is expected to increase dramatically over the next few decades, and, in accordance with its interpretation of Board policy, it wants to deplete these reserves, should they exist, as quickly as possible. It is attempting to accomplish this with minimal disturbance to nearby residents by directionally drilling from the edge of a section of Crown surface land, rather than on Mr. McLuskey's property, as it had originally intended.

Gulf stated that the proposed sour well would be classified as a level 1 facility[1]. The closest residence is 420 metres from the proposed well site, a substantially greater distance than the 100 metres separation required under ERCB interim directive ID 81-3[2] for level 1 wells. Portable H_2S monitoring equipment would be on the lease after running the intermediate casing and a mud logging unit would be employed while drilling the lower portion of the hole. An H_2S scavenging additive would be kept on the lease and added if mud returns were found to contain gas. The rig would be equipped with a degasser, and a flare pit and stack would be constructed on the lease.

Gulf further stated that drilling crew emergency procedure exercises would occur at least once per week. A first aid service vehicle, complete with a paramedic, oxygen, and mobile radio would be stationed on the lease. The paramedic would be responsible for maintaining a current inventory of all nearby residents and, in the event of an uncontrolled release of H_2S, for evacuating the residents, their pets, and their livestock. All of this would be set out in an emergency plan which, following approval by the Board, would be explained to nearby residents.

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1 Interim directive ID 81-3: Minimum Distance Requirements Separating New Sour Gas Facilities From Residential And Other Developments defines a level 1 facility as a sour gas well with a potential H_2S release rate of 0.3 m^3/sec or less, or any other sour gas facility with a potential to release 300 m^3 of H_2S or less.

2 Ibid.

Regarding increased traffic on local roads, Gulf explained that the only heavy road use would be when it moved its equipment into and out of the lease. At each time, approximately 50 truckloads of equipment would be using the roads over a 3-day period. Gulf said it is considering the use of a campsite to minimize crew shift traffic while the well is being drilled. In response to intervener questioning, Gulf stated that it would repair any damage done to local roads and would likely leave the roads in a slightly upgraded condition. Gulf also indicated that it was prepared to take whatever further action was practical to control the traffic volume and the driving practices of its staff and contract personnel.

During discussion of the intervener's concerns regarding noise, Gulf said that it was prepared to accept the requirement for a diesel-electric drilling rig. As well, should a campsite be utilized, it would draw electricity from the main rig generators, rather than having its own generating equipment. In addition to these special conditions, Gulf agreed to comply fully with the Board's interim directive ID 80-2, regarding noise, and, if necessary, take a noise level survey, prior to and during the drilling operations.

Gulf indicated that it intended to obtain water, for drilling the proposed gas well, from water wells that would be drilled on the lease. As far as protecting water aquifers in the area from contamination by drilling fluids, Gulf would use 610 metres of surface casing as a barrier to fluid transfer. A nontoxic high gel/chemical mud would be used to drill to total depth. Gulf would control the overall water usage for the entire operation in order to limit the size of the drilling sump as far as possible. In addition, it would be prepared to sample water wells, within 1 kilometre (km) of the well site, and also determine their depth or zone of origin, before spudding.

Fluid loss from the sump would be minimized by locating it in an area of impermeable soil. If this is not possible, the sump would be lined or the sump fluids held in steel tanks. The size of the sump would be minimized by recycling sump fluid back into the mud system. After drilling and completion or abandonment activities have been completed, Gulf proposed to inject as much sump fluid as possible into zones below the surface casing and through the surface casing/intermediate casing annulus, in accordance with the Board's interim directive on subsurface disposal of sump fluids and then to deep-trench any remaining sump fluids.

Gulf did not believe that its drilling rig would be a fire hazard or a significant threat to wildlife in the area. As well, Gulf said it would adopt its standard practice of diking fuel tanks and disposing of used lubricating oil by burning in a pit or hauling to a sanitary site.

Another issue of concern to the interveners was whether Gulf had any plans for additional meetings with nearby residents, in order to discuss the impact of the well on their neighbourhood. Gulf expressed the view that it had made sufficient contact and, in any event, further contacts respecting the emergency plan would take care of this.

2.2 Views of the Local Residents Group

Mrs. Martin, on behalf of the above-mentioned group, expressed her dissatisfaction at the hazards and disadvantages that the well would bring to the surrounding residents. The hazards included a possible release of H_2S, increased traffic on narrow roads, and a possible forest fire. Other concerns were possible road damage, noise, odours, possible depletion of freshwater aquifers, contamination of freshwater aquifers by drilling fluid disposal, disturbance to wildlife, and a decrease in property values. Regarding the emergency evacuation that could be required in the event of a release of H_2S, Mrs. Martin stated that the area has an increased population in summer due to an influx of non-residents, and that Gulf's plans had not addressed this matter.

On the issue of possible depletion of freshwater aquifers, Mrs. Martin said that most of the water wells in the area are already low producers and that, if Gulf uses ground water for drilling its well, it may cause the wells to deteriorate further. Mrs. Martin also requested that if the application is approved, Gulf meet with the residents who are close to the proposed well site to discuss any concerns that they may have.

2.3 Views of the Canadian Wildlife Federation

Mr. Evans, on behalf of the Wildlife Federation, questioned the need for the well and referred to the fact that a surplus of gas now exists in Alberta. He also stated that the Wildlife Federation has a concern for animal life in the area and requested that Gulf do everything possible to lessen the well's impact on the environment. Mr. Evans went on to indicate that the Wildlife Federation was also concerned with the safety of residents in the area and questioned whether Gulf had established sufficient community contact prior to making its application to the Board. The Wildlife Federation suggested, by way of closing argument, that, if the applied-for licence is granted, it should be conditioned to require that Gulf conduct noise level surveys and monitor wildlife, both prior to and after drilling. It also requested that Gulf be required to have fire-fighting equipment at the proposed well site, conduct a water-quality survey, post a bond for possible road damage, limit traffic to and from the campsite, and conduct a population influx study of the area to ensure that Gulf would be aware of transients that may be in the area in the case of an emergency. The Wildlife Federation also requested that Gulf increase the size of the area from which it would be prepared to evacuate people in the case of an emergency and also to inform people within the enlarged area of what its emergency plans are. Finally, the Wildlife Federation requested that Gulf be required to establish a community-industry liaison committee to improve communications with residents in the area.

2.4 Views of the Board

The Board notes that Gulf has leased the mineral rights to the lands in question and believes there is a justified need for the exploratory well to determine if reserves are present. The Board does not agree with the Wildlife Federation that the existence of a gas surplus at this point in time removes the justification for drilling wells, particularly when they are exploratory in nature.

The Board recognizes the concerns of the interveners regarding the increase in traffic associated with the drilling of a well. However, it notes that the heavy traffic would be for a very limited period and that Gulf has agreed to take action to minimize traffic problems. The Board is satisfied that, with appropriate planning by Gulf, traffic impact can be held to an acceptable level. The Board does not have jurisdiction to require Gulf to post a bond respecting road damage and is satisfied this will be adequately controlled by municipal authorities.

The Board is satisfied that potential noise problems are not such to preclude drilling of the well, but believes that, if the well is drilled, Gulf should take all steps possible to limit noise from the drilling operation. In this regard, the Board notes that Gulf stated it was prepared to use a diesel-electric rig. It would expect Gulf to comply with the requirements of interim directive ID 80-2 concerning maximum permissible day-time and night-time noise levels. The Board also believes that it would be prudent for Gulf to conduct a noise level survey, prior to initiating any drilling operations, to determine the background noise levels. Background noise levels would be very helpful in dealing in a meaningful fashion with any possible future complaints. The Board would expect Gulf to be prepared to take appropriate action respecting noise complaints should they arise.

The Board has a number of regulations in place to safeguard ground water aquifers from contamination or other negative impacts during the drilling of a well. The Board believes that these would adequately protect nearby water wells, but recognizing the sensitivity of the ground water system in this area, the Board will require Gulf to conduct a water well survey of all domestic or farm water wells within 1 km of the proposed well site prior to spudding the well. This survey would include aquifer depth measurements, water analysis, and pump rate tests for each well.

The Board is concerned about Gulf's proposed use of ground water aquifers as a source of the water requirements for the drilling operation. The Board believes that Gulf should attempt to obtain another source for this water, however, as it does not have jurisdiction over the drilling of water wells or the use of ground water supplies, it cannot require Gulf to find another water source. If a licence is issued, the Board would expect Gulf to obtain the appropriate water use permits from Alberta Environment and would

require Gulf to provide the Board with copies of these permits prior to spudding the well. The Board intends to send a copy of this decision report to Alberta Environment. Additionally, if Gulf decides to proceed with its plans to utilize the ground water, the Board would require that the water well survey referred to earlier be expanded to include all domestic and farm water wells within 1.5 km of the proposed well site.

The Board does not believe that the containment of sump fluids in an earthen pit, as proposed by Gulf, should pose any problems. The Board notes that its regulations and the mineral surface lease, from Alberta Energy and Natural Resources, require that the sump be located in impermeable soil and that Gulf has agreed to comply with this requirement. If a suitable site is not available, the Board expects Gulf to contain the sump fluids in steel tanks or a suitably-lined pit.

On the issue of sump clean-up, the Board agrees with Gulf's plan to inject as much of the sump fluid as possible downhole. In regards to the surface disposal of any remaining sump fluids, the Board would expect Gulf to comply fully with the requirements of interim directive ID-OG 75-2. In view of the sensitive nature of the ground water aquifers in this area, the Board is concerned about Gulf's proposal to utilize deep-trenching for the disposal of any remaining sump fluids. The Board believes that the remaining volumes should be very small, and, thus, that Gulf should mix the material in the existing sump. The Board would therefore discourage the use of deep-trenching at this particular site should the well proceed.

The Board expects Gulf to plan its lease to minimize the chance of a forest fire. In this regard, the Board expects Gulf to comply fully with all regulations concerning equipment spacing and the construction of flare pits.

The Board does not believe that the drilling operation or possible future producing operations would pose a significant threat to wildlife or to other parts of the environment in the area. Additionally, the Board does not believe that property values in the area would be appreciably affected by the proposed well.

If the well is to be drilled, the Board considers it necessary for Gulf to have in place an adequate sour gas emergency contingency plan and to inform the public of the plan prior to commencement of drilling. The Board notes the uncertainty of the potential H_2S content of any gas discovered and its effect on the evacuation radius. The Board believes that it is appropriate to utilize the highest probable H_2S content in determining the evacuation radius, while drilling the well, and to adjust the radius when the actual H_2S content becomes known. In addition, the Board notes that Gulf's current plan is lacking in details respecting the procedures to ensure that non-residents in the area would not be overlooked in the unlikely case of an emergency. The Board would require

that a more comprehensive plan, clarifying the evacuation radius, communication of the plan to the public and other relevant issues, be submitted before drilling could proceed.

Although the Board does not believe that a community-industry committee, as suggested by Mr. Evans, should be required, it would encourage Gulf to arrange a meeting with nearby residents to discuss their concerns regarding the proposed well.

3 DECISION

For the reasons outlined in Section 2.4 of this report, and having regard for the public interest, the Board is satisfied that the drilling of the proposed well is justified. Accordingly, it would be prepared to grant the application of Gulf to drill the well, subject to all normal conditions, to the undertaking given by Gulf at the hearing and mentioned earlier in this report and to the following special conditions:

Prior to commencement of drilling, the applicant shall

a) file an acceptable emergency plan with the Board, and

b) conduct a water well survey of all domestic and farm wells within 1 km of the proposed well site, or

c) should Gulf proceed with its plan to drill water supply wells for use in the drilling operations, conduct the water well survey for all wells within 1.5 km of the proposed well site.

DATED at Calgary, Alberta, on 8 June 1982.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
Vice Chairman

V. E. Bohme
Board Member

E. R. Brushett
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY BLAKE RESOURCES LTD.
FOR A LICENCE TO DRILL A WELL IN THE
MAZEPPA FIELD IN THE HIGH RIVER AREA

Decision 82-24
Application No. 820250

1 INTRODUCTION

1.1 The Application and Hearing

On 5 March 1982, Blake Resources Ltd. (Blake) applied to the Energy Resources Conservation Board (Board) for a licence to drill the well BLAKE ET AL MAZEPPA 6-16-19-28 (6-16) for the purpose of obtaining gas production from the Crossfield member. Blake indicated that the gas could contain approximately 300.0 moles per kilomole of hydrogen sulphide (H_2S).

A public hearing of the application was held before the Energy Resources Conservation Board (Board) on 28 May 1982 in Calgary, Alberta with G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and E. J. Morin, P.Eng. sitting.

Mr. & Mrs. W. Poelman (the Poelmans), who own the south-half of the NE 1/4 16-19-28W4M and reside approximately 800 metres from the proposed well, opposed the application.

The location of the proposed well, the Poelman residence and other relevant geographical features are shown on the Figure.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives	Witnesses
Blake Resources Ltd. B. S. Schultz	B. S. Schultz, P.Eng. J. D. Sorkilmo M. J. Okrusko W. J. Zajac
W. J. and M. E. Poelman M. E. Poelman	M. E. Poelman G. Poelman
Energy Resources Conservation Board Staff K. F. Miller J. R. Nichol, P.Eng. F. G. Sorenson	

2 CONSIDERATION OF THE APPLICATION

2.1 Views of Blake

The applicant stated that although it had fulfilled its farm-in commitment to drill three wells in the general area, the proposed well would have to be drilled before the 23 November 1982 expiry of the mineral lease. It considered the 6-16 well to be exploratory in nature but estimated the well could encounter 10 to 15 metres of pay. Blake estimated that section 16 could contain 340 10^6 m^3 of gas in place but stated that a gas sales contract would likely not be available until 1986. In addition, it stated that a gas plant and pipeline would have to be in place before the well could be placed on production.

Blake stated that it had investigated alternative well locations in Lsd 14-16 and Lsd 8-16. It had rejected the Lsd 14-16 site because of landowner preference, and had rejected the Lsd 8-16 site because of its proximity to the Poelman residence. Blake had chosen the 6-16 site because it was satisfactory to the landowner and non-resident tenant, and because it would satisfy Blake's geological considerations. In addition, the 6-16 site would be further removed from the Poelman residence.

Blake stated that it was proposing to provide temporary access to the well from the east, along the half-section fence line. It added that it had considered an alternative access road from the south but had rejected it because it would result in severence of a field being farmed by the tenant. However, having regard for the concerns expressed by the Poelmans respecting problems associated with the increased traffic and the movement of heavy equipment, Blake stated it would endeavour to obtain approval to provide temporary access from the south. Blake indicated that it planned to provide permanent access to the well, if it is completed as a producer, from Highway 2 located approximately 400 metres to the west. Blake acknowledged that it had not obtained the necessary approvals and that it would expect some difficulty in that regard.

Blake stated that its experience in the area indicated that it would not encounter special drilling problems but that it would be prepared in any case. The drilling rig would be equipped according to regulations and would be manned and supervised by well trained and knowledgeable drilling personnel. The rig would utilize a drilling mud degasser and flaring system to strip out and burn any gas which reached the surface. Specially trained safety personnel and equipment would be on location to assist in the detection of H_2S and to assist the crews if a problem occurred.

Blake stated that it had not determined the source of its water for the drilling operations but did not intend to drill water wells. It had not investigated the location of existing domestic water wells in the area.

Blake said that it was prepared to discuss its emergency response plan with the Poelmans and that it would notify them prior to penetrating the sour gas zone. In the event of a significant release of sour gas, Blake would immediately assess the danger and implement its emergency plan accordingly. The plan provides for the orderly notification and

evacuation of residents, if appropriate, and for the ignition of the gas if lives are threatened. In addition to its plan to notify area residents by telephone, Blake indicated it would dispatch members of its drilling crews to the residences most likely to be in danger because of prevailing wind conditions.

Blake acknowledged the Board's interim directive ID 80-2 respecting acceptable noise levels and stated that it had considered using a diesel-electric drilling rig. Regardless of the type of rig it contracted, Blake stated that it would be prepared to meet the guidelines which specify maximum day-time noise levels of 65 decibels and maximum night-time levels of 50 decibals, 15 metres from a residence.

Blake stated it would utilize a conventional earthen pit for the containment of drilling fluids. Blake further stated that it would comply with interim directive ID-OG 75-2 respecting the disposal of sump fluids and indicated that it was not aware of any special or unique conditions which would necessitate special sump fluid handling and disposal methods.

Blake stated that its plan for completing, stimulating, testing and producing the well had not been finalized. It would be necessary to stimulate the well in order to achieve economic flow rates and a production test was planned. Blake acknowledged that it would be necessary to obtain a flaring permit from the Board and agreed it would consider special testing procedures to minimize flaring. Its flaring operation might last approximately 24 hours and would involve a flare stack for combustion of the sour gas and dispersion of the combustion products. In addition, Blake would employ an expert to provide downwind monitoring for the presence of sulphur dioxide and hydrogen sulphide.

2.2 Views of the Poelmans

The Poelmans stated an opinion that the proposed well would endanger their family and have a negative impact on their way of life. The Poelmans stated that their four children are athletically inclined and enjoy running, bicycle riding and horseback riding in the general area. The Poelmans believed that the uncertainty about the safety of the well and the increased traffic near their residence would hamper their family's activities. In addition, Mrs. Poelman noted that compensation will be paid to the landowner who does not reside in the area and who will not be adversely affected to the degree her family would be. The Poelmans would prefer that Blake provide temporary access to the well from the south. The east-west road to the south is a wider, higher grade road, known in the area as the Blackie Road. The Poelmans indicated that this would eliminate one of their concerns and stated it would not seriously impact on the tenant because the road would only be temporary. Gordon Poelman stated that the field south of the proposed well was flat land farmed in two parcels by the tenant and suggested that the temporary road could parallel that division with little or no inconvenience.

The Poelmans explained that much of their concern was the result of not being informed by the oil and gas companies as to what was going on. Mrs. Poelman explained that they had seen wells in the area flaring gas

but were never advised and were never really sure whether they should be concerned. The Poelmans indicated that their concerns were somewhat relieved having had the opportunity to learn more about Blake's emergency response plan and its drilling practices and procedures. They expressed concern that the response plan indicated that landowners would be the fifth group to be contacted by telephone in the event of an emergency, and that their name was well down the list of landowners. The Poelmans stated that the prevailing winds were from the south-southwest and indicated that notification by telephone may not be adequate. Mrs. Poelman suggested that it would be much better to have someone dispatched immediately to warn them of any potential hazard but questioned whether the evacuation procedure would work as well as was intended.

The Poelmans expressed concern about the effect the proposed well could have on their domestic water well which is about 61 metres deep and located approximately 0.8 kilometres from the proposed gas well. They believed the quality of their water had been affected by previously drilled wells in the area and said they had detected a sulphurous, rotten egg smell in the water.

2.3 Views of the Board

The Board notes that Blake has fulfilled its farm-in commitment to drill three wells in its Okotoks-High River properties but must commence the proposed well by November 1982 if it is to maintain the mineral lease. The Board does not fully agree with the applicant that the proposed well should be considered exploratory, and expects that there is a very good chance of it being successful. The Board recognizes, however, that a well does have to be drilled to further delineate the pool and to establish recoverable reserves which will in turn, influence future gas contracts available to Blake.

The Board is satisfied that the proposed well is properly located having regard for the agricultural use of the land and the impact on the area residents. The Board recognizes the concerns of the Poelmans respecting safety and the inconvenience of having the temporary road located close to their residence but is aware that the heavy traffic would be limited to a short period of time during the drilling, completing, and if necessary, the testing phases of the well. Also, access from the east would make it easier for the applicant to keep the Poelmans informed, and warn them of danger in case of emergency. The Board has no comment with regard to the Poelmans claim that compensation for the proposed well may be paid to the wrong persons. The Board notes that Blake has stated it would attempt to obtain approval to provide an alternative temporary access road from the south. Having regard for the concerns expressed by the Poelmans, the Board believes that temporary access from the south is preferable, but access from the east is also acceptable. The Board further notes that if the well is drilled and is successful, Blake had proposed to provide permanent access to the well from the west, from Highway 2. The Board believes it is unlikely Blake will be able to obtain approval from Alberta Transportation and, if such is the case, the Board expects that Blake would propose suitable alternatives for permanent access when it is required.

The Board recognizes that formation pressures and drilling practices in the general area have been well established and believes that the well could be drilled in compliance with Board regulations without seriously impacting the area residents. In addition, the Board is satisfied that its regulations governing testing and production operations are adequate but believes it would be unreasonable to expect that the well could be drilled without causing some nuisance and inconvenience to the Poelmans. In that regard, the Board believes that the major source of complaint from area residents is the result of post stimulation clean-up and testing operations. As a result, the Board believes it would be appropriate for Blake to investigate alternative methods of stimulating and testing the Crossfield member, for example into a pipeline system. If the well must be tested in the conventional manner, it would be necessary for Blake to obtain prior Board approval. The Board would expect Blake to make every effort to minimize the flaring period before it would issue an approval.

The Board notes that Blake is not planning to drill water wells to supply its drilling operations and is satisfied that normal surface hole drilling practices and the surface casing would protect any aquifers from which the area residents obtain their water. The Board believes, however, that it may be prudent for Blake to conduct a survey of domestic water wells in the area and to consider quality and quantity tests to establish a standard should future problems be experienced by the Poelmans or other area residents. The Board further notes that Blake stated it was prepared to comply with the Board's sump fluid disposal requirements and accepts Blake's evidence that no special fluid handling and disposal procedures are necessary. It would expect Blake to take the appropriate measures were it to discover a high water table or gravel beds during the construction of the sump pits.

Having regard for the expected H_2S content of the gas and population density in the area, the Board believes that, if a well is drilled, it is imperative that a comprehensive and workable emergency response plan be in place prior to commencement of drilling. The Board is, for the most part, satisfied with Blake's emergency response plan for the drilling phase of the well. The Board agrees with the Poelmans that the most difficult part of any emergency plan is that of effective communications, but believes that Blake's plan would provide for the safety of the residents on a priority basis in the event of an emergency. The Board believes that it is very important that Blake inform the area residents of its intended activities. In this regard, the Board recognizes the difficulties of making personal contact in every instance and is prepared to accept mail delivery of an information package if Blake can determine that such would be preferred by the resident. Blake should be prepared to sit down and discuss its plans with any resident who so desires. The Board notes that the Poelmans and one other family reside on the NE 1/4 of section 16 and believes that Blake should make a special effort to keep them informed particularly during the period when the sour gas zone would be entered. In this regard, the Board notes that Blake agreed at the hearing to discuss its emergency plan in more detail with the Poelmans.

If a successful well is drilled and completed, but is suspended until it can go on production, the Board will require that Blake develop an

appropriate plan, including provisions for periodic updates of the list of local residents.

3 DECISION

For the reasons given in this report, the Board is satisfied that the drilling of the proposed well is justified. It is further satisfied that the well can be drilled safely and with minimum effect on the residences of the area. Accordingly, the Board is prepared to grant the application and will issue a well licence in due course.

ISSUED at Calgary, Alberta, on 16 June, 1982.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

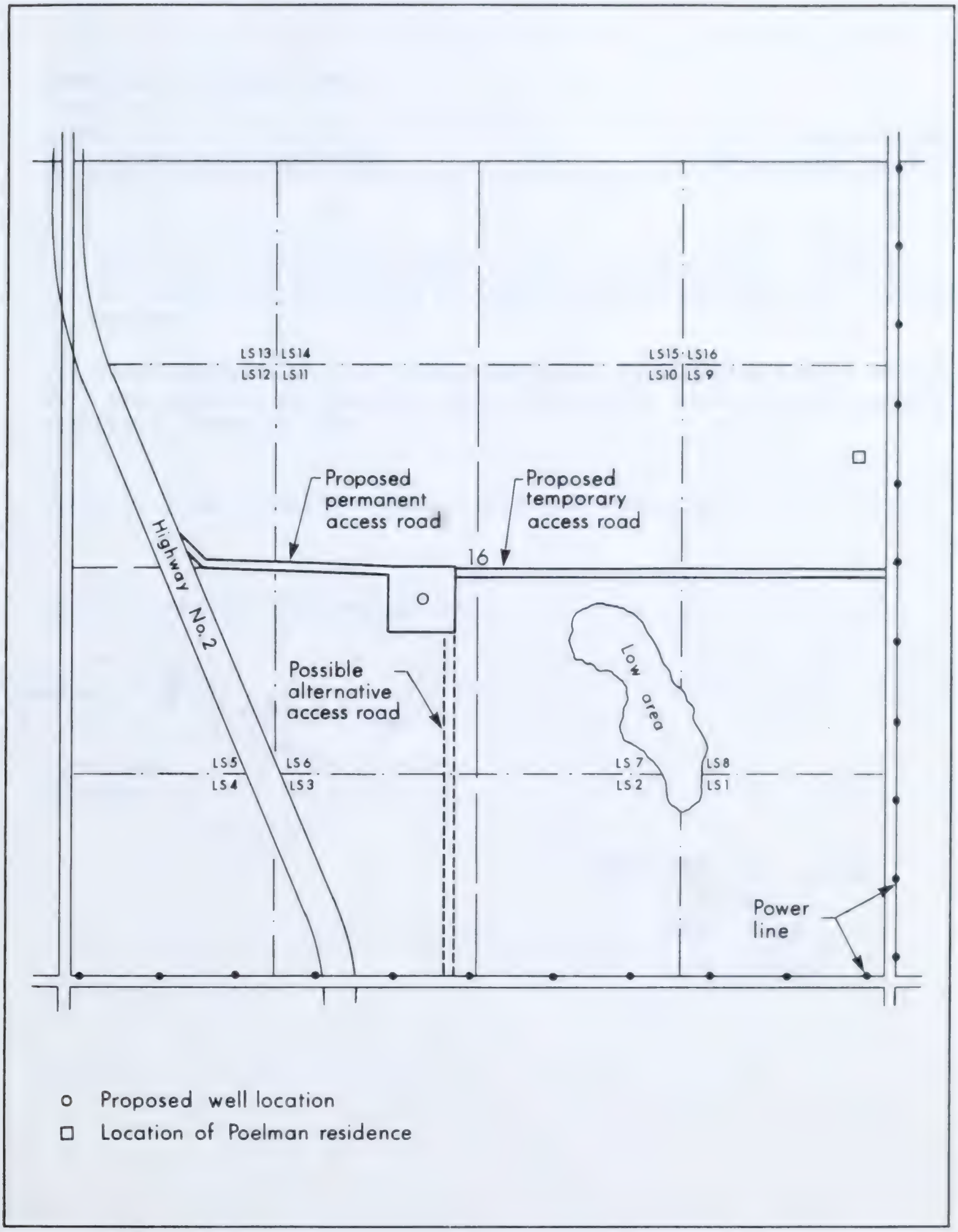
G. J. DeSorcy, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

E. J. Morin

E. J. Morin, P.Eng.
Acting Board Member



BLAKE AT AL MAZEPPA 6-16-19-28 W4M PROPOSED WELL SITE.

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA CANADA

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

COMPULSORY POOLING ORDER
ORDER NO. P16
CIGOL BIGLK 11-15-53-26
ST. ALBERTA BIG LAKE FIELD

Decision 82-25
Proceeding No. 820395

The Board has reviewed the report of the sitting member, attached hereto, respecting Proceeding No. 820395 requesting that Order No. P16 be rescinded.

The Board agrees with the recommendation of the sitting member and will, with the approval of the Lieutenant Governor in Council, issue an order rescinding Order No. P16.

DATED at Calgary, Alberta this 15th day of June 1982.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

COMPULSORY POOLING ORDER
ORDER NO. P16
CIGOL BIGLK 11-15-53-26 | Decision 82-25
ST ALBERT BIG LAKE FIELD | Proceeding No. 820395

1 INTRODUCTION

1.1 Background

Order No. P16 was issued on 5 April 1961 for the purpose of pooling all tracts within section 15, township 53, range 26, west of the 4th meridian, for the production of gas from the Ostracod Sandstone Zone from the well CIGOL BIGLK 11-15-53-26. The subject well was abandoned on 22 November 1968.

On 4 March 1982, Alberta Energy and Natural Resources, Mineral Resources Division, advised the Energy Resources Conservation Board (the Board) that all natural gas leases for the subject section had expired and that there were now no active Crown agreements. The Division requested that the pooling order be rescinded and a recommendation was forwarded from the staff to the Board recommending that the order be rescinded.

In accordance with the requirements of section 74 of the Oil and Gas Conservation Act, the request for rescission of Order No. P16 was set down for public hearing.

1.2 The Hearing

Proceeding No. 820395 was considered at a hearing on 11 June 1982 in Calgary, with V. E. Bohme, P.Eng., Board Member, sitting. No interventions or objections to the rescission of the compulsory pooling order were filed.

The Energy Resources Conservation Board staff was represented at the hearing by J. R. Nichol, P.Eng.

2 FINDINGS

The sitting member of the Board finds that there is no justification for keeping Order No. P16 in force because:

- the well CIGOL BIGLK 11-15-53-26 has been abandoned;

- o all natural gas leases respecting the section covered by the pooling order have expired; and

- o no objections to rescinding the order were received.

3 RECOMMENDATION

The sitting member recommends that the Board, with the approval of the Lieutenant Governor in Council, issue an order rescinding Order No. P16.

DATED at Calgary, Alberta on 11 June 1982.

ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme
Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

CANADIAN SUPERIOR OIL LTD.
APPLICATION FOR AN ORDER DIRECTING
THE PROPORTIONS OF GAS TO BE PURCHASED
IN THE BRAZEAU RIVER ELKTON-SHUNDA A POOL

Decision 82-26
Application 810959

The Board has reviewed and adopted the report of its examiners, attached hereto, respecting the application by Canadian Superior Oil Ltd. for direction regarding the proportioning of the common purchasers' acquisitions of gas from the Brazeau River Elkton-Shunda A Pool.

Accordingly, the Board directs that the proportions of gas that TransCanada PipeLines Limited and Alberta and Southern Gas Co. Ltd. shall purchase from each producer or owner in the Brazeau River Elkton-Shunda A Pool offering gas for sale to them shall be as set out in the recommendations of the examiners' report.

DATED at Calgary, Alberta on 29 June 1982.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy
Vice Chairman

Attachment

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

CANADIAN SUPERIOR OIL LTD.
APPLICATION FOR AN ORDER DIRECTING THE PROPORTIONS OF GAS TO BE PURCHASED IN THE BRAZEAU RIVER ELKTON-SHUNDA A POOL

Examiners' Report E82-9
Application 810959

1 INTRODUCTION

1.1 Application and Hearing

Farries Engineering (1977) Ltd., on behalf of Canadian Superior Oil Ltd., applied pursuant to section 52, subsection 4(b) of the Oil and Gas Conservation Act (now section 40 under the Revised Statutes of Alberta, 1980), for an order directing the proportion of gas from the Brazeau River Elkton-Shunda A Pool (the pool) which TransCanada PipeLines Limited (TransCanada) and Alberta and Southern Gas Co. Ltd. must purchase from each producer or owner in the pool offering gas for sale to them.

The application was considered at a public hearing in Calgary, Alberta, on 3 March 1982, with Board-appointed examiners G. A. Warne, P.Eng., H. R. Keushnig, P.Eng., and J. R. Nichol, P.Eng., sitting.

CDC Oil & Gas Limited,[1] operator of the Nordegg Gas Unit No. 1 (the Unit), submitted an intervention. Alberta and Southern Gas Co. Ltd. intervened only to cross-examine and present argument. TransCanada, the other common purchaser, did not intervene.

Table 1 shows those who appeared at the hearing and gives the abbreviations used in this report.

1.2 Background

The Brazeau River Elkton-Shunda A Pool is a non-associated gas pool designated by Board Order G 3006 (Figure 1). The pool includes the Elkton Member and the Shunda Formation which are comprised of a series of widespread cyclical platform sheets of limestone or dolomite interbedded with carbonate mud. These units are correlatable throughout the pool.

---

1 Now Canterra Energy Ltd.

Gas reservoirs were formed within the Elkton Member as a result of updip erosion of the subcrop edge and subsequent burial and capping by tight Jurassic shales and cherts. The Shunda Formation extends to the northeast beyond the erosional edge of the Elkton Member and entrapment of gas is due to porosity pinchout. The applicant's two wells were drilled in this area beyond the erosional edge of the Elkton Member, and hence they contain pay only in the Shunda Formation.

Since the separation between the Elkton Member and Shunda Formation is relatively thin in some areas, and because of the presence of extensive natural fracture systems, the two formations are viewed as a single reservoir.

The Unit and the wells included in the pool are shown on Figure 1. A list of the wells with descriptive information follows:

Well Location (W5M)	Finished Drilling Date	Status	Abbreviation Used in Report	Operator
11-28-44-11	76-05-03	capped	11-28	Gulf Canada Resources Inc.
6-30-44-11	70-07-09	shut-in	6-30	CDC
10-3-44-12	65-04-07	producing	10-3	CDC
10-11-44-12	71-01-09	producing	10-11	CDC
2-15-44-12	76-02-10	producing	2-15	CDC
2/6-16-44-12	68-03-16	producing	6-16	CDC
6-22-44-12	73-12-20	producing	6-22	CDC
7-23-44-12	68-08-26	producing	7-23	CDC
8-24-44-12	78-11-10	producing	8-24	CDC
6-25-44-12	78-09-06	producing	6-25	CDC
7-29-44-12	68-02-03	producing	7-29	CDC
10-34-44-12	70-07-24	abandoned	10-34	Home Oil Company
10-2-45-12	78-06-30	capped	10-2	Canadian Superior
6-12-45-12	77-05-28	capped	6-12	Canadian Superior

Production from the pool began in 1969 and all production has occurred from within the Unit.

In 1977 and 1978 the applicant drilled its 10-2 and 6-12 wells and was unable to obtain a gas contract. It then submitted, in April 1981, an application (810260) for a common purchaser order. As a result, TransCanada and Alberta and Southern were declared common purchasers of gas from the pool by Board Order Misc 8113, effective 3 September 1981.

The 11-28 well, owned by Gulf Canada Resources Ltd., was drilled in May 1976, and is also outside the Unit.

1.3 Preliminary Matter

At the beginning of the hearing, CDC requested the Board to review and rescind Board Order Misc 8113, which declared the common purchasers of gas from the pool. CDC contended that a common reservoir link exists within the Shunda Formation between the Brazeau River Elkton-Shunda A Pool and the Brazeau River Elkton-Shunda B Pool, and that the delineation of the pools should be reviewed before considering the matter of proportioning. However, the examiners decided that review of the common purchaser order and pool designation were matters beyond the scope of the present hearing. They suggested that if CDC had new evidence and wished to do so, it could submit separate applications to the Board for a review of these other matters.

2 ISSUES

The examiners believe that the issues related to the application are:

- the need for a direction respecting the proportioning of the common purchasers' acquisitions from the pool, and

- if there is a need, the method of proportioning the gas taken from the pool.

3 NEED FOR DIRECTION RESPECTING PROPORTIONING

3.1 Views of Canadian Superior

Canadian Superior submitted that its 10-2 and 6-12 wells continue to be drained by wells producing from the Unit, and that it has been unable to obtain an acceptable gas nomination for these wells from either of the common purchasers. On 8 September 1981, Canadian Superior requested that the common purchasers provide their interpretation of Canadian Superior's share of total production from the pool. Initially, TransCanada advised Canadian Superior orally that it was not prepared to allocate pool production to Canadian Superior. However, on 4 December 1981, TransCanada, on behalf of both common purchasers, offered to purchase 14.1×10^3 cubic metres per day (m^3/d) of gas from the Canadian Superior wells in order to offset drainage, provided the Unit nomination was decreased by an identical volume.

Canadian Superior claimed that this 14.1×10^3 m^3/d fixed daily nomination (approximately 2 per cent of the current total pool production rate) offered by TransCanada would be inadequate to offset drainage from its lands. It proposed that 4.216 per cent of the pool production would be a more reasonable share.

Canadian Superior's efforts in negotiating an equitable share of pool production with CDC, the operator of the Unit, also were unsuccessful.

Since reasonable attempts at negotiations with the common purchasers and CDC had failed to produce an acceptable sharing agreement, Canadian Superior contended that it had been discriminated against.

3.2 Views of CDC

CDC stated that all the wells in the Unit, with the exception of the 10-11 and 6-30 wells, have most of their effective pay in the Elkton Member, and hence, most of the gas production from the Unit is from that formation. It further stated that, since the 6-30 well was the only nearby well producing from the Shunda Formation, it was the only well in the Unit draining the Canadian Superior wells. Thus, it contended that, because the 6-30 well has been shut-in since May 1981, it could not now be draining Canadian Superior's lands.

CDC doubted that significant drainage could be occurring from the applicant's property through the Elkton Member because there is little effective communication between the two formations. It stated that the absence of significant communication was supported by a pressure measurement on the Shunda Formation in the 6-30 well before it went on production in September 1973. This pressure measurement indicated that, despite production from nearby wells over a three-year period, the initial pressure in the 6-30 well in 1973 was only 862 kilopascals below the initial pool pressure. In addition, CDC noted that a pressure measurement of the Shunda Formation at the 6-25 well in September 1978 indicated that the Shunda Formation at this well was still at the initial pool pressure. It argued that the existence of limited Elkton-Shunda communication was also substantiated by the build-up pressures taken in July and December 1981 at the shut-in 6-30 well which indicated that continued production from other wells in the pool had little effect on the Shunda Formation in this well.

CDC stated that since the production from the Unit has minimal effect on Canadian Superior's wells, there was no need for a direction from the Board respecting the proportions of gas to be taken from each well operator in the pool.

3.3 Views of the Examiners

The examiners believe that some drainage is continuing to occur from the applicant's lands, even though the 6-30 well is shut-in, because production has reduced the pressure in the parts of the pool from which production has been taken and gas will move toward these low pressure

areas. The examiners observe that the section between the Elkton Member and Shunda Formation appears to be relatively thin in a number of areas and may have been penetrated by natural fractures. In addition, they note that in completing the wells, fractures may have been induced between the two formations and it is doubtful that separation could have been maintained when casing was cemented. In view of the above, and considering that several of the wells are completed in both the Elkton Member and the Shunda Formation, the examiners are satisfied that communication exists between the two zones.

The examiners believe that CDC's evidence concerning reservoir pressures indicates that communication is poor in certain parts of the pool, but does not establish that the zones are isolated from each other. Further, the examiners note that the degree of communication is variable, both in horizontal and vertical directions. Indeed, the repeat formation tests in the 6-25 well referred to by CDC showed that an upper Shunda unit had experienced drainage by adjacent wells while a lower one had not.

The examiners are satisfied that a reasonable, but unsuccessful attempt has been made by Canadian Superior to reach an acceptable agreement on its share of pool production. Further, since drainage continues to occur from the applicant's lands, there is a need for the Board to direct the proportions of gas which the common purchasers must purchase from each producer in the pool offering gas for sale.

4 METHOD OF PROPORTIONING

4.1 Views of Canadian Superior

Canadian Superior stated that, in view of the difficulties and differences of interpretation involved in preparing hydrocarbon pore volume maps, proportioning should be based on the net pay and the production spacing unit (PSU) area of each well. It contended that wellbore parameters should be determined on a consistent basis and recommended that sonic logs be used since they are available for all wells. It said core information should be used to calibrate the sonic logs and to determine porosity cut-offs.

Canadian Superior noted that the Board had, in previous decisions, recognized larger PSUs by applying certain criteria to allocate credit for undrilled tracts with proven reserves to existing wells. It submitted that this procedure was reasonable and could be applied in the Brazeau River Elkton-Shunda A Pool. It entered an exhibit illustrating how the procedure might be applied indicating that reserves in 22 drilled and undrilled sections in the pool could be recognized in proportioning production. Canadian Superior stated that section 1-45-12 W5M, in which it had an interest, was not presently eligible for inclusion in a PSU

since the entire section was not of common ownership, but if common ownership could be achieved, there is a possibility it could then be included in a larger PSU.

Canadian Superior objected to CDC's proposed method of proportioning whereby material-balance calculations would be used to determine reserves for the pool while volumetric calculations would be used to determine reserves for its 10-2 and 6-12 wells. It contended that this was inequitable since the two methods of calculating reserves for the pool gave different results. Canadian Superior also objected to the Unit being viewed as a PSU, as suggested by CDC, because the Unit included drilling spacing units (DSUs) which have not been proven productive and included lands which are outside the designated pool.

4.2 Views of CDC

CDC argued that Canadian Superior's share of the total pool production should be based on the ratio of the volumetrically determined gas in place (GIP) of the 10-2 and 6-12 wells to the material-balance determined GIP for the entire pool. CDC stated that the material-balance method would be the best method for calculating the GIP for all the wells in the pool; however, because the 10-2 and 6-12 wells have never been produced, their GIP could only be determined on a volumetric basis. CDC contended that the material-balance method should be used since it avoids the geological uncertainties and gives an accurate and reliable GIP for the entire pool. CDC said that all available information should be used to calculate the wellbore parameters for the Canadian Superior wells.

CDC stated that the Unit should be considered as a single PSU. It contended that the Unit's share of pool production should therefore be allocated to the individual wells in the Unit at its discretion.

CDC further stated that, if Canadian Superior's share of pool production were based on the method Canadian Superior proposed, it would allocate too large a percentage of pool production to Canadian Superior wells, and cause the Unit to suffer drainage. It also stated that TransCanada's offer to purchase 14.1×10^3 m^3/d of gas from Canadian Superior is a fair offer and, if the Board considered it necessary to direct the allocation of production, it had no objection to this amount being translated into a percentage of production (approximately 2 per cent of the current pool production rate).

4.3 Views of Alberta and Southern

Alberta and Southern requested that, if the Board should set proportions of gas to be acquired from the pool, it should specify only the total amount to be taken by the two common purchasers. It stated that the arrangements for sharing the production had already been worked out between the common purchasers. It further stated that TransCanada

had agreed to buy all of the gas allocated to Canadian Superior pursuant to the application and that Alberta and Southern would not be purchasing any gas directly from Canadian Superior.

4.4 Views of the Examiners

The method of proportioning proposed by CDC is inequitable because CDC used the material-balance method to calculate reserves attributable to the Unit and the volumetric method to calculate reserves attributable to Canadian Superior wells. This discriminates against the Canadian Superior wells because the material-balance method yields significantly higher reserves than the volumetric method. For example, the gas in place for the entire pool determined by material balance, is about 13 750 $\times 10^6$ m^3, while that determined by the volumetric method is in the order of 9920 $\times 10^6$ m^3. Since only the volumetric method is applicable to each area, the examiners conclude that it should be used to determine the proportion of production which should be allocated to each producer offering gas for sale.

The examiners agree that it would be reasonable to allocate reserves to DSUs not yet drilled to which proved reserves can be confidently attributed. They also agree that it would be reasonable to apply principles broadly similar to those developed for oil-well PSUs in allocating gas reserves to undrilled DSUs. However, particularly in the interior portion of the Unit, there does not appear to be a need to be as restrictive in defining the location of the producing well within the central area as for normal oil-well PSUs.

In determining areas attributable to productive wells, the examiners believe it reasonable to follow the principles described in the Appendix of this report which were developed after reviewing

- Board policy set forth in previous decisions,
- the provisions respecting oil-well PSUs in sections 5.040, 5.050, and 5.070 of the Oil and Gas Conservation Regulations, and
- the characteristics of the Brazeau River Elkton-Shunda A Pool and the fluids it contains.

The validated areas attributed to each productive well by the examiners using these principles are shown in Figure 2. These validated areas may be changed as a result of future development or ownership changes.

The examiners conclude that the following formula would be appropriate for allocating the common purchasers' acquisitions from the Brazeau River Elkton-Shunda A Pool:

$$\text{Proportion attributable to validated area} = \frac{\text{Pore volume of validated area}}{\text{Sum of pore volumes of all validated areas}}$$

The pore volume of each validated area would be determined using the parameters of its associated well.

The examiners believe that the wellbore net pay and porosity values used in the proportioning formula should be determined using all available data. On this basis, the examiners determined net pay values from the cored wells using cut-offs of 3-per cent porosity and 0.1 millidarcy permeability. Where a well was only partially cored, they determined the log cut-off equivalent to 3-per cent porosity from a correlation of core porosity with the sonic log. Where no core was available, the examiners generally used sonic logs to determine net pay. The examiners interpreted a travel time from a general correlation of core-determined porosity with sonic log response of 170 microseconds per metre to be equivalent to 3 per cent porosity for all uncored wells except the 2-15 well. A sonic log was not available for the 2-15 well and the compensated neutron log was used to determine net pay. Zones which were interpreted as shale from the gamma ray logs were excluded from net pay.

The examiners observe that there does not appear to be sufficient variation in water saturation to warrant including it in the proportioning formula. Accordingly, only the area, net pay, and porosity values for each well were determined by the examiners and these values are shown in Table 2. The corresponding values determined by Canadian Superior and CDC, where such values were available have also been provided.

The Unit's share of the pool allocation would be determined on the basis of the relationship of the validated pore volume of the Unit to the the validated pore volume for the entire pool. However, the unit operator would be expected to distribute production within the Unit so as to avoid drainage of validated areas outside the Unit. If production is not distributed on a reasonable basis, an operator may apply to the Board for restrictions on wells producing at excessive rates.

5 RECOMMENDATIONS

The examiners recommend that:

- the Board direct that the proportion of acquisitions of gas the common purchasers shall take from each owner or producer offering gas for sale from the Brazeau River Elkton-Shunda A Pool be determined in accordance with the formula set out in section 4.4, and

- the pore volumes determined from the area, net pays, and porosities as set forth in columns 1, 4, and 7 of Table 2 be used in the proportioning formula for each existing qualifying well.

DATED at Calgary, Alberta on 9 June 1982.

G. A. Warne

G. A. Warne, P.Eng.

H. R. Keushnig

H. R. Keushnig, P.Eng.

J. R. Nichol

J. R. Nichol, P.Eng.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Canadian Superior Oil Ltd. (Canadian Superior) J. K. Farries, P.Eng.	J. K. Farries, P.Eng. of Farries Engineering (1977) Ltd. D. H. Hadley, P.Eng.
Alberta and Southern Gas Co. Ltd. (Alberta and Southern) W. Lenhardt	
CDC Oil & Gas Limited (CDC) B. K. O'Ferrall	M. Azzam L. Fenwick, P.Eng. K. Geppert, P.Geol. J. Wansleeben, P.Eng.
Energy Resources Conservation Board staff K. Fisher, C.E.T. K. L. Bieber, P.Geol. N. Ramdin C.J.C. Page	

TABLE 2 VALUES FOR THE PROPORTIONING FORMULA
THE BRAZEAU RIVER ELKTON-SHUNDA A POOL

	1	2	3	4	5	6	7
WELL LOCATION	VALIDATED AREA hectares	WELLBORE NET PAY (metres)			POROSITY (%)		
		Canadian Superior	CDC	Examiners	Canadian Superior	CDC	Examiners
11-28-44-11	259	-	2.44	2.3	-	4.80	6.5
6-30-44-11	777	13.71	11.59	11.8	7.70	9.60	8.3
10-3-44-12	259	10.05	10.37	10.2	9.15	10.15	9.3
10-11-44-12	518	11.58	15.86	11.5	7.00	6.19	6.5
2-15-44-12	518	9.54	-	9.7	9.00	-	8.8
2/6-16-44-12	518	7.80	12.51	14.3	12.30	10.20	10.5
6-22-44-12	777	11.58	16.47	15.4	8.39	7.90	7.0
7-23-44-12	518	14.63	18.00	13.7	9.00	10.10	8.0
8-24-44-12	777	15.97	6.30	7.7	5.40	5.20	5.1
6-25-44-12	777	17.16	16.20	16.2	10.00	10.81	9.3
6-29-44-12	777	7.92	6.41	7.6	6.40	6.17	6.4
10-2-45-12	259	7.04	2.75	5.5	6.50	4.60	6.1
6-12-45-12	259	6.67	5.49	6.7	6.30	6.30	6.3

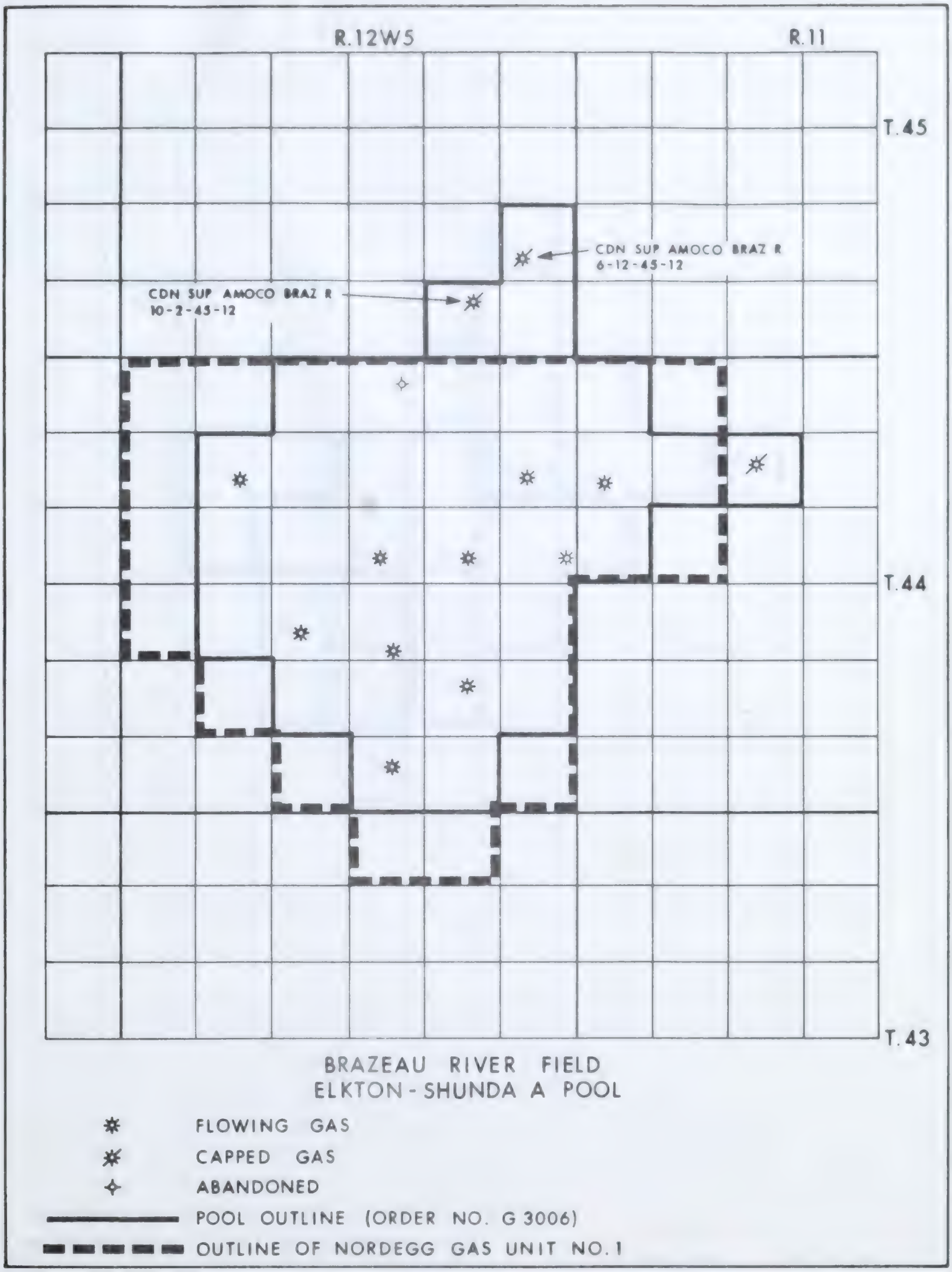


FIGURE 1 TO EXAMINERS' REPORT: APPLICATION NO. 810959

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

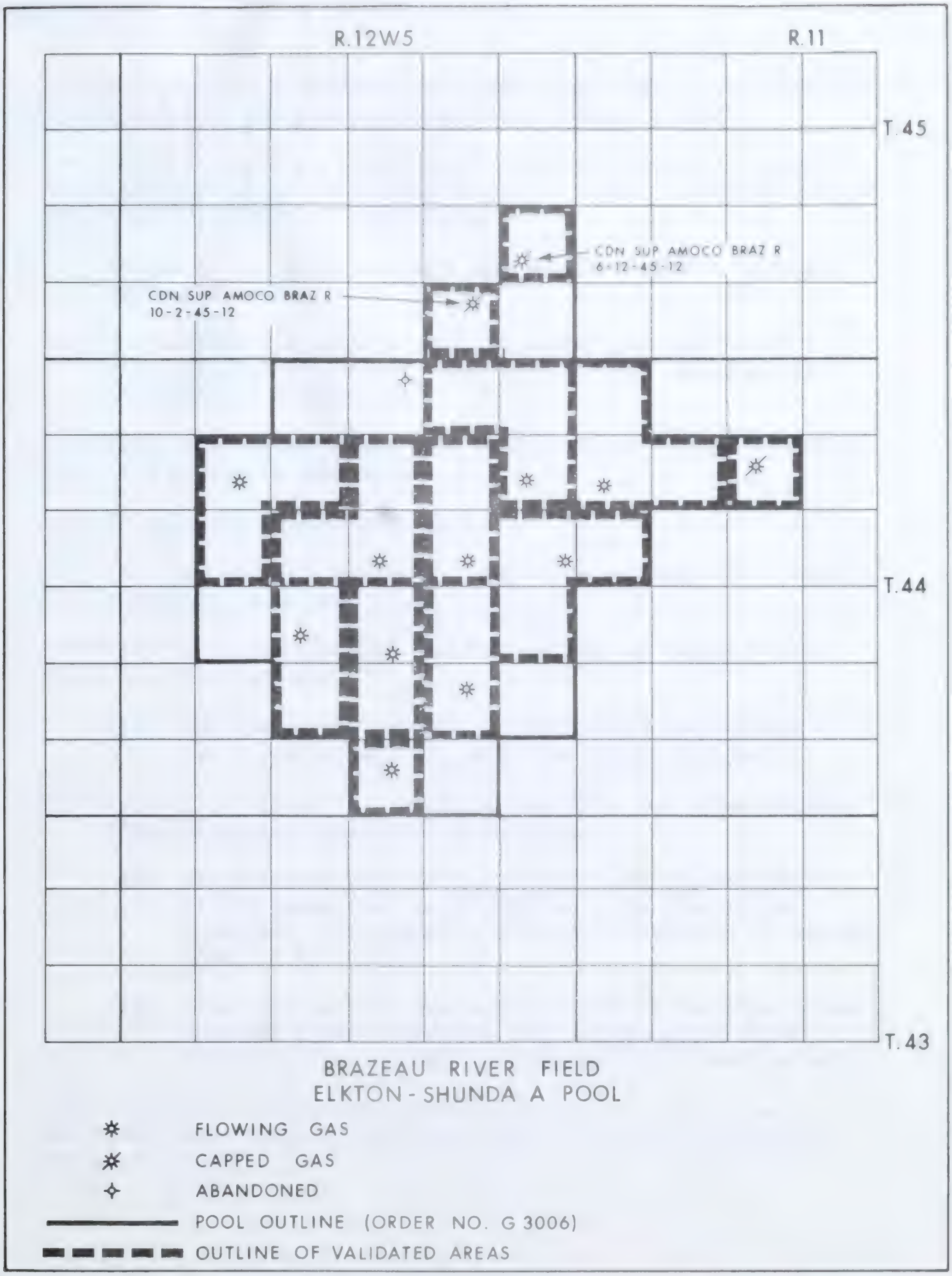


FIGURE 2 TO EXAMINERS' REPORT: APPLICATION NO. 810959

APPENDIX

Principles Applied in Determining the Additional Area Attributable to Productive Wells in the Brazeau River Elkton-Shunda A Pool

1. The area attributed to a well shall contain only whole laterally adjoining DSUs which are pooled or are of common ownership and the well must be capable of production.

2. (a) Not more than three sections may be attributed to a single producing well.

   (b) The maximum dimension of the validated area attributed to a well measured in a north-south or east-west direction shall not exceed 3.2 kilometres.

3. A drilling spacing unit shall not be attributed to the productive well of a validated area unless

   (a) it contains a productive well, or

   (b) there is adequate geological and other evidence of reservoir continuity such that

      (i) a productive well could be drilled on target within the DSU, and

      (ii) the gas within the DSU is practicably recoverable by the producing well to which the DSU is attributed.

   (c) subject to clause (b), it is an undrilled DSU lying between DSUs containing productive wells where

      (i) the distance between the points where the wellbores of the productive wells intersect the productive formation, referenced to a common elevation, is not more than 5.8 kilometres, and

      (ii) more than half of the undrilled DSU is included between straight lines connecting the corresponding sides or corners of the offsetting DSUs having productive wells.

4. The increase in a well's production rate due to allocation of additional area must not seriously affect the drainage patterns within the pool.

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

DOME PETROLEUM LIMITED
PROPANE EXTRACTION PLANT
FORT SASKATCHEWAN

CHEVRON STANDARD LIMITED
FRACTIONATION PLANT
FORT SASKATCHEWAN

Decision 82-27
Applications 810916 & 811009

1 INTRODUCTION

1.1 The Applications

Dome Petroleum Limited applied (Application 810916) pursuant to section 38[1] of The Oil and Gas Conservation Act (the Act), for approval of a scheme for fractionating natural gas liquids (NGL) at its existing cavern storage facilities located in the north half of section 14 and the south half of section 23, township 55, range 22, west of the 4th meridian in the Fort Saskatchewan Field. The proposed plant would enable the applicant to fractionate up to 7840 cubic metres of NGL per day (m^3/d) and thereby recover some 4190 m^3/d of propane and 3650 m^3/d of butane. No sulphur or sulphur compounds would be emitted to the atmosphere.

Chevron Standard Limited applied (Application 811009) pursuant to section 38[1] of The Oil and Gas Conservation Act for approval to expand its existing fractionation facilities in the south half of section 14, township 55, range 22, west of the 4th meridian in the Fort Saskatchewan Field. The expansion would increase plant capacity from 4452 m^3/d to 17 500 m^3/d of NGL from which 6920 m^3/d of ethane, 5130 m^3/d of propane, 3424 m^3/d of butanes, and 2026 m^3/d of pentanes plus would be recovered. Sulphur dioxide emission would be increased from 1.19 to 2.4 tonnes/day (t/d).

1.2 The Hearing

The applications were considered concurrently at a public hearing in Calgary on 13 April 1981 with N. Berkowitz, P.Eng., C. J. Goodman, P.Eng., and G. A. Warne, P.Eng., sitting. The participants in the hearing are listed in the following table.

Following the hearing, the Board issued an interim decision on 23 April 1982 approving the subject applications. The following is a full report on the basis for the decision.

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1 Now section 26 of the Oil and Gas Conservation Act.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Dome Petroleum Limited (Dome) W. M. Smith F. M. Saville	A. Ilnyckyi, P.Eng. Dr. A. H. Younger, P.Eng. E. Small, P.Eng.
Chevron Standard Limited (Chevron) L. M. Sali D. C. Edie	Dr. K. Godard, P.Eng. J. Zedde, P.Eng.
Alberta Energy Company Ltd. Esso Chemical Company Hudson's Bay Chemical Company Limited (AEC/ECC/HCC) D. G. Davies	
Alberta Gas Ethylene Company Ltd. (AGEC) F. R. Foran	
Alberta Natural Gas Company Ltd. (ANG) J. R. Smith, Q.C.	
Amoco Canada Petroleum Company Ltd. (Amoco) F. B. Matthews, P.Eng.	
Canadian Hunter Exploration Ltd. (Cdn. Hunter) B. K. O'Ferrall	
Dow Chemical of Canada Limited (Dow) C. E. Repchinsky	
Esso Resources Canada Ltd. (Esso) D. G. Hart, Q.C.	
Gulf Canada Resources Inc. (Gulf) J. D. Anderson	

THOSE WHO APPEARED AT THE HEARING cont'd

Principals and Representatives (Abbreviations used in Report)	Witnesses
PanCanadian Petroleum Limited (PanCanadian) W. J. Hope-Ross, Q.C. E. S. Dector	
Petro-Canada Exploration Inc. (Petro-Canada) J. W. Gallagher	
Sulpetro Limited (Sulpetro) R. Beattie	
Texaco Canada Resources Ltd. (Texaco) W. F. Muscoby	
Energy Resources Conservation Board staff C.J.C. Page, Board Solicitor W. J. Schnitzler, P.Eng. P. K. Tse, C.E.T. R. N. Spencer, C.E.T.	

2 ISSUES

The Board considers the principal issues raised by the applications to be

- o feedstock availability and the need for the plants,
- o technical and environmental aspects of the plants, and
- o other matters, notably the proprietary rights of producers respecting NGL and the potential impact of the proposed plants on the Alberta petrochemical industry.

3 FEEDSTOCK AVAILABILITY AND THE NEED FOR THE FACILITIES

3.1 Views of Dome

Dome and its partners currently produce and purchase NGL in Alberta and elsewhere in Canada, and fractionate it in Sarnia for sale in eastern regions of North America. However, greater production of NGL resulting from increased gas deliveries, as well as shutdown of inefficient fractionation facilities in Saskatchewan and lack of spare capacity in Dome's Sarnia fractionator, now necessitate additional facilities. The proposed plant would provide the required additional capacity and at the same time permit more of Alberta's natural resources to be upgraded in the province rather than elsewhere. The recovered propane would be marketed in Alberta, Saskatchewan, and the U.S. mid-west.

Long-term supplies of NGL for the proposed plant have been secured, and would mostly be obtained from Dome operations and Amoco. Hudson's Bay Oil and Gas Company Limited was originally expected to be a joint venture partner with Chevron, but after being merged with Dome, withdrew its planned supply of feedstock to Chevron and committed it to the applicant.

Dome noted that, having regard for the proposed size of its and Chevron's plants, no particular advantage would accrue from processing its feedstock through Chevron's plant, which includes a de-ethanization section and is designed for different feedstock composition. As well, Chevron's plant would not be completed until a year after Dome's feedstock would become available. Dome submitted therefore that its application should be considered quite independently of Chevron's.

3.2 Views of Chevron

Chevron referred to its applied-for 17 500 m^3/d of feedstock and the firm nominations totalling 17 342 m^3/d, and pointed out that it could operate the proposed expanded plant even if feedstock from some fields were not available. It stated that if it could only access feedstock from its Kaybob South plant, it would be prepared to build the fractionation facility for that volume alone.

Chevron also confirmed that none of the feedstock referred to in its application was also counted upon in Dome's, and that its proposed plant would not have spare capacity to handle Dome's feedstock.

Chevron submitted that the existing plant was designed to receive 4452 m^3/d of NGL, and to produce propane, butanes, and pentanes plus, and that the proposed expansion, which would increase the plant inlet capacity to 17 500 m^3/d, would permit production of ethane as well as of propane, butanes, and pentanes plus.

3.3 Views of the Interveners

Interveners raised no serious questions respecting the need for Dome's proposed plant or the availability of feedstock for it.

However, with respect to Chevron's application, AGEC noted that the only approved feedstock for the proposed expansion would be derived from the Judy Creek Field, and that the availability of feedstocks from the Elmworth, Wapiti, and Kaybob South fields were doubtful since the proposed plants have not yet received Board approval. AGEC also pointed out that HBOG's portion of feedstock from the Kaybob South Field would be excluded. It therefore submitted that Chevron's application was premature and that a ruling on it should be deferred until availability of sufficient feedstock was assured.

3.4 Views of the Board

The Board notes that both Dome's and Chevron's feedstock nominations are contracted and that no feedstocks are double counted by being included in both applications. It agrees with AGEC that a portion of Chevron's expected feedstock derives from deep-cut facilities in Elmworth, Wapiti, and Kaybob South fields which have not yet been approved, but accepts that Chevron would build a smaller plant, capable of processing assured volumes, if it could not access some of the potential feedstock sources.

The Board also notes that Dome merely proposes to recover propane and butanes plus, while Chevron would recover ethane, propane, butanes, and pentanes plus, and therefore agrees that the two applications should be viewed independently of each other.

The Board further concurs with the applicants that increasing feedstock availability has created a need for the plants proposed by Dome and Chevron.

4 TECHNICAL AND ENVIRONMENTAL ASPECTS

4.1 Views of Dome

Dome stated that its proposed plant would meet the Board's noise control guidelines since all motors would be electrically driven and contained within buildings. The proposed plant would be designed to conserve all NGL during normal plant operation and to achieve an energy efficiency of over 90 per cent in fuel use, whereas its Sarnia plant only achieves a 75 per cent efficiency. Plant upset conditions requiring NGL flaring

are not anticipated to exist for a total of more than once a year and to last longer than 6 hours. However, the plant would be shut down for two days per year for scheduled maintenance, and during those periods, NGL in the plant would be purged and flared. No smoke or sulphur dioxide (SO_2) would be emitted to the atmosphere.

Dome also indicated its intent to maintain a buffer zone between the proposed plant and the river valley, and noted that the nearest residence would be more than 500 m distant.

4.2 Views of Chevron

Chevron's proposed plant would be designed to meet all existing noise control guidelines, require no flaring of NGL during plant start-up and normal operation, and would emit no black smoke during emergency flaring. SO_2 emissions from the plant would increase from 1.19 to 2.40 t/d, but ground level concentrations of oxides of sulphur (SO_x) and oxides of nitrogen (NO_x) would meet Alberta Environment's clean air standards. The nearest residence is across the river, about 1.2 kilometres to the northwest.

4.3 Views of the Interveners

None of the interveners commented on the technical and environmental aspects of the applications.

4.4 Views of the Board

The Board accepts that both Dome's and Chevron's proposed plants would meet pollution control standards and achieve proper conservation levels. It is satisfied with the other technical and environmental aspects of the plants.

5 OTHER MATTERS

In addition to the matters considered above, the Board has focussed attention on the proprietary rights of producers to extract NGL at field plants, a matter specifically raised by the Chevron application, and on the potential impact of both proposals on the Alberta petrochemical industry.

5.1 Proprietary Rights of Producers

Chevron submitted that its proposal would allow gas producers to upgrade their NGL and realize a greater return on risk capital which they invested years ago. It added that the support for the proposal by the feedstock producers showed that it was in the public interest.

Several interveners supported the proposed plants on the basis that they would afford gas producers an opportunity to upgrade the liquids portion of their gas streams. It was suggested that nominations for capacity from feedstock producers throughout Alberta indicated the merits of Chevron's application.

The Board believes that, provided it is in the Alberta public interest, gas producers should have opportunities for recovering separate products from gas under their control, and agrees that Chevron's proposal would provide such an opportunity.

5.2 Potential Impact on the Petrochemical Industry

Only the Chevron plant was viewed as perhaps having an adverse impact on the petrochemical industry. Dow submitted that Chevron's proposal, together with several other applied-for ethane deep-cut facilities, would result in duplication of facilities currently supplying AGEC's ethylene plants, and consequently increase the cost of ethane to the Alberta petrochemical industry. Dow therefore asked the Board to defer a ruling on Chevron's application until the full impact of the project on the petrochemical industry of Alberta has been determined.

Notwithstanding the current softening of world demand for most petrochemicals, the Board believes that ethane from existing plants in Alberta will not likely meet projected requirements by the mid-1980s, and that Chevron's proposal could help assure adequate supplies without significantly impacting on the cost of Alberta ethane. In the Board's view, the potential adverse impact on Alberta's petrochemical industry is not sufficient to warrant denial of the application or a deferral of a ruling on it.

6 FINDINGS

The Board finds that both proposed plants are needed, and that the technical and environmental aspects of each are acceptable. With respect to the economic impact issues raised by Chevron's application, the Board finds that deferral of a ruling on that application would not be in the public interest.

7 DECISION

Having considered all relevant evidence, the Board, subject to approval by the Minister of the Environment with respect to environmental matters, is prepared to grant both applications.

DATED at Calgary, Alberta on this 30th day of June, 1982.

ENERGY RESOURCES CONSERVATION BOARD

N. Berkowitz, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

G. A. Warne

G. A. Warne, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

APPLICATIONS BY SHELL CANADA LIMITED
FOR PERMITS TO CONSTRUCT
PRODUCT PIPELINES IN THE NORTHEAST
EDMONTON AREA

Decision 82-28
Application 820114

1 INTRODUCTION

1.1 The Application

Shell Canada Limited (Shell) applied to the Energy Resources Conservation Board, pursuant to the Pipeline Act, for a permit to construct pipelines and related facilities as follows:

(a) 16.01 kilometres (km) of parallel 273.1-millimetre (mm) outside diameter (OD) and 219.1-millimetre outside diameter pipelines, for the transmission of middle distillates and gasolines respectively, from the southwest quarter of section 31, township 53, range 22, west of the 4th meridian (Point K near Highway 21) to the Edmonton Marketing Terminal (EMT) in the SE 1/4 32-52-23 W4M,

(b) 1.49 km of 323.9-mm OD parallel pipelines for the transmission of middle distillates and gasolines from the EMT to the Texaco pipelines in Lsd 15-32-52-23 W4M, for transmission to the Alberta Products Pipeline Terminal (APPL) in Lsd 10-4-53-23 W4M,

(c) 2.20 km of twin 457.0-mm OD parallel pipelines for the transmission of middle distillates and gasoline from the EMT to the Interprovincial Pipelines Ltd. (Interprovincial) terminal in the SE 1/4 5-53-23 W4M, and

(d) 2.30 km of 273.1-mm OD single pipeline for the transmission of semi-refined products from the EMT to the TransMountain Pipeline Ltd. (TransMountain) terminal in the SW 1/4 5-53-23 W4M.

The proposed pipeline route is shown on Figure 1.

1.2 Background

The Board received an earlier application from Shell for a permit to construct two pipelines from the approved Scotford refinery to northeast Edmonton, and for a number of relatively short pipelines to move refined and semi-refined products to storage and terminal facilities. A hearing of those matters was conducted on 10 July 1981 to consider Shell's application, resulting in a decision[1] approving Shell's perferred routing northeasterly of Highway 21. The area to the southwest of Highway 21 was deferred. In September, 1981, a Board inquiry[2], initiated at the request of the Lieutenant Governor in Council[3], was held to consider a possible pipeline corridor route into the Edmonton refinery area.[4] Shell has now applied for the

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1 Energy Resources Conservation Board, 1981. Application for Permits to Construct Pipelines and Related Facilities in the Edmonton-Skaro Area. ERCB Decision Report 81-19, Calgary, Alberta.

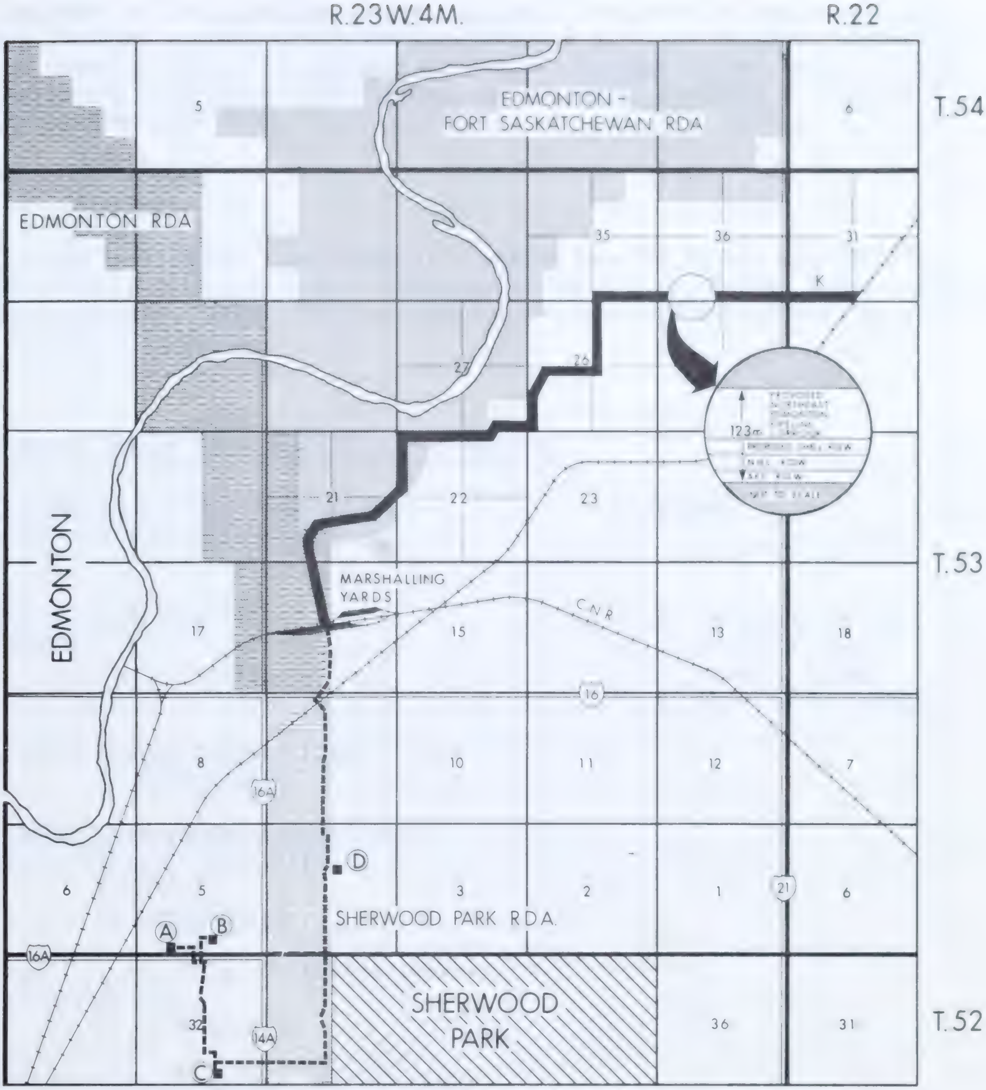
2 Energy Resources Conservation Board, 1981. Northeast Edmonton Pipeline Corridor Inquiry. ERCB Decision Report 81-29, Calgary, Alberta.

3 Order in Council 545/81, made pursuant to section 24(1) of the Energy Resources Conservation Act, now section 22(1) of the Energy Resources Conservation Act, being chapter E-11 of the Revised Statutes of Alberta, 1980.

4 Order in Council 545/81 provides in part:
" ..... upon the recommendation of the Honourable the Minister of Environment, the Lieutenant Governor in Council, pursuant to section 24(1) of the Energy Resources Conservation Act, requests the Energy Resources Conservation Board to make inquiries and report on:

(a) the most desirable route for a pipeline corridor from the Sherwood Park West and Edmonton Restricted Development Areas north of the Canadian National Railway (CNR) marshalling yards to a point near Highway 21, and

(b) the width of a corridor that would be appropriate, having regard for future pipeline requirements in the area."



--------- APPLICATION NO. 820114

▬▬▬ POSSIBLE PIPELINE CORRIDOR

Ⓐ TRANS MOUNTAIN PIPELINE LTD. TERMINAL

Ⓑ INTERPROVINCIAL PIPELINE LTD. TERMINAL

Ⓒ EDMONTON MARKETING TERMINAL

Ⓓ ALBERTA PRODUCTS PIPELINE TERMINAL

FIGURE 1 PROPOSED SHELL PIPELINES
NORTH-EAST EDMONTON AREA

remainder of the pipeline system originally deferred by the Board, and has included a routing through the possible pipeline corridor as part of the overall scheme. A significant portion is also in the Sherwood Park Restricted Development Area, along the alignment assigned for pipeline transportation.

1.3 Hearing

The application was considered at a public hearing on 4-5 May 1982, in Edmonton, Alberta, with G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and C. J. Goodman, P.Eng., sitting. Those who appeared at the hearing are identified in Table 1.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Shell Canada Limited (Shell) R. M. Curtis	P. E. Boisseau, P.Eng. B. G. Gregg, P.Eng. R. J. Lamarr, P.Eng. G. R. Ursenbach, P.Eng.
Alberta Energy Company (AEC) B. Zalmanowitz	
Genstar Corporation and Genstar Gypsum Limited (Genstar) R. Abells D. Zalmanowitz	
Donald F. and Helen Catherine Jackson (the Jacksons) E. J. Walter	
Northwestern Utilities Limited (NUL) B. Zalmanowitz	
Johannes Prinz von Thurn und Taxis (Prinz von Thurn) I. F. Grape V. Schwab, Q.C.	
Alberta Environment T. R. Bossenberry	

TABLE 1 THOSE WHO APPEARED AT THE HEARING (continued)

Principals and Representatives (Abbreviations used in Report)	Witnesses
Energy Resources Conservation Board staff (Board staff) R. J. Allman, P.Eng. E. G. Fox, P.Eng. K. F. Miller G. J. Vogt	

1.4 The Interventions

The interventions covered a wide range of issues, and brought to light a number of concerns regarding jurisdictional as well as land-related matters. Interventions were also received in support of the application.

Genstar was disturbed about the proliferation of rights of way across its property, and the negative effect that this could have on its plans for future building construction.

The Jacksons believed that the pipelines should be placed next to property lines, and were also concerned about the effects of pipeline construction on their agricultural activities.

Prinz von Thurn claimed that the timing for construction of the applicant's pipelines was premature and should be delayed. His counsel also raised a number of jurisdictional and procedural issues related to the application and hearing.

Although AEC supported the application, it opposed the sharing of its present right of way with the applicant's pipelines.

1.5 Jurisdictional and Procedural Matters

During the hearing the Board heard several motions made on behalf of Prinz von Thurn, which the Board ruled on following each motion.

At the opening of the hearing, it was submitted by counsel for Prinz von Thurn that the Board's jurisdiction had been fettered by the failure of the Lieutenant Governor in Council to act on the recommendation of the Board contained in the Inquiry Report 81-29, issued following the Board's northeast Edmonton pipeline corridor inquiry. Counsel suggested that because a news release alleged that the Minister of Environment has

accepted the Board's recommended northeast Edmonton pipeline corridor, and because the Board can only act with the approval of the Lieutenant Governor in Council, the Board could not consider Shell's application until its jurisdiction was restored to it, and that its jurisdiction could only be restored following the government acting upon the Board's recommendation. It was further submitted that since the Board has made recommendations to the Lieutenant Governor in Council, that it was incumbent upon the Lieutenant Governor in Council to either accept or reject those recommendations.

At the hearing, the Board expressed the opinion that it had jurisdiction under the Pipeline Act with respect to the location of pipelines and that neither the request for the inquiry by the Lieutenant Governor in Council, the Board's recommendations resulting from that inquiry, nor the fact that the Lieutenant Governor in Council had not fully acted on the recommendations removed that jurisdiction. The Board stated that it did not believe that its jurisdiction had been fettered and that Shell, in the proceeding, must justify its proposed route as being acceptable in the public interest. The Board stated that it would approve or deny the subject application on the basis of the evidence received at the hearing. Acccordingly, the Board denied the motion.

The second motion brought by counsel for Prinz von Thurn was to require that the evidence given during the proceeding be on oath or affirmation. The basis for this motion was that counsel anticipated that very substantial matters relating to compensation, which are not within the jurisdiction of the Board, would become the issue of further litigation, and for those anticipated proceedings they wanted to have before them sworn evidence given during the hearing.

The Board indicated that it had not been a practice of the Board to take evidence under oath. The Board saw no reason to depart from that practice in the particular case as it related to the proceeding before the Board. The motion was denied.

A third motion put forth was to have each Shell witness presented individually with the opportunity to cross-examine that witness following his direct evidence. Counsel stated that cross-examining a panel of witnesses made examination very difficult, and that such cross-examination would become totally ineffective.

The Board ruled that it did not believe cross-examining on a panel basis would prejudice the intervener's right to cross-examine. The Board stated that it was not prepared to change its normal practice and accordingly denied the motion.

Counsel brought a fourth application to have the Board compel the attendance, as a witness, of Mrs. Judy Schutz, Manager Corridor Implementation, Land Assembly Division, Alberta Environment. Counsel submitted that because of her position with the Department of

Environment, she would be a material witness to the proceeding and that she could tell the Board what is planned in respect of the corridor if the corridor recommendation were to be implemented. It was suggested that such information was most relevant to the hearing.

In respect of the motion, the Board indicated that it was in a position to consider the merits of the proposed location of the line, notwithstanding that someday there might be a corridor in the area of the application. The Board stated that it did not consider whether or not there is or will be a corridor to be relevant to the particular application before the Board and the decision that it must make. The Board was not prepared to compel the attendance of Mrs. Schutz and the motion was denied.

The fifth motion of counsel for Prinz von Thurn was to have two members of the sitting division of the Board disqualify themselves from hearing the application on the basis of an apprehension by his client of bias on the part of those two members. It was submitted that since those two members of the Board panel had participated as sitting members in the northeast Edmonton pipeline corridor inquiry, and since that panel had made recommendations to the Lieutenant Governor in Council as contained in Inquiry Report 81-29, there was not only a fear of anticipated bias but of actual bias.

The Board panel stated that it considered it was a division of the Board properly constituted under the Energy Resources Conservation Act, and that it intended to continue with the proceeding because it did not see a basis to do otherwise.

2 THE ISSUES

The Board considers the major issues to be:

- need for the pipelines,
- the pipeline route,
- technical design, safety, and corridor-related matters, and
- special matters raised at the hearing.

3 NEED FOR THE PIPELINES

The matter of need for the pipelines was dealt with by the Board at the earlier Shell hearing.[5] Since only a portion of the pipeline route was considered at that time, and bearing in mind possible changes since then, the Board believes it should consider the matter of need again.

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5 See footnote 1.

3.1 The Applicant's Views

Shell stated that on the basis of its projected market demands for refined products, it had elected to build a refinery at Scotford and transport the products via pipelines to the Interprovincial, Trans-Mountain and APPL terminals. These plans had not changed in spite of the present economic climate and changes in ownership of the refinery, and company policy was to proceed as scheduled. The applicant contended that from an economic point of view, pipelines were vastly superior to other modes of transportation, and that the present application was merely a continuation of the first part of the system previously approved by the Board. Under these circumstances, Shell believed that the need for the pipeline had been established.

3.2 The Interveners' Views

Counsel for Prinz von Thurn questioned the viability of the Scotford refinery project, noting that the original corporate partnerships for the scheme had been terminated and that the economics of the project were in question. Concern was expressed about feedstock for the refinery, and the fact that this could be in jeopardy because of changed corporate relationships.

None of the other interveners questioned the need for Shell's pipelines.

3.3 The Board's Views

The Board believes that the applicant supplied sufficient information to show that the construction of the Scotford refinery is proceeding as planned, notwithstanding certain changes in ownership, and that the entire pipeline system is a necessary part of the overall project. While the Board recognizes that certain economic circumstances have changed since the need for the first part of the pipeline system was established, it is of the opinion that the need for the remaining lines has not significantly lessened.

4 THE PIPELINE ROUTE

4.1 The Applicant's Views

Shell stated that the pipeline route selected was based on an earlier comprehensive engineering study for the entire route from the Scotford refinery to the EMT site. Since that time, a number of independent evaluations of potential pipeline routes or corridors in the same area had been made by others, and the findings had supported the original study.

Shell maintained that its proposed route was selected totally independent of any formal corridor considerations, and that in fact the route had been chosen a considerable time before a possible corridor was investigated or recommended. Shell then proceeded to elaborate on the essential criteria it had considered in assessing an optimum route, listing them as: the maximum use of existing Restricted Development Areas (RDA); location of its lines wherever possible adjacent to existing or proposed linear disturbances (eg. C.P. railway, AEC pipelines, proposed NUL line); minimum conflict with existing or proposed subdivisions, and integration wherever possible with regional and local master plans; careful consideration of risk factors created by the pipeline, with priority given to human safety; the least possible environmental impact; and finally minimum overall investment costs.

In further support of its choice of route, Shell explained that a number of alternative locations had been investigated. The first of these was an exit route from the Sherwood Park West RDA that would be south of Highway 16 and north of the Town of Sherwood Park. This alternative was rejected because the land here is designated for prime urban development and a pipeline route would seriously interfere with this potential development. The second alternative route considered was one north of Highway 16 but south of the CNR marshalling yards. This would have paralleled the CP railway where a number of pipelines are already located. Because all available space along the railway is more or less fully occupied by these existing pipelines, this alternative had to be ruled out. Two other routes were then considered north of the CNR marshalling yards, one being the proposed route and the other an alternative to the south. The latter had the disadvantage of crossing major industrial development, both existing and planned, and the added disadvantage of high land costs through the area. The conclusion reached by Shell following this investigation, and analysis of other possible variations and combinations of routes in the area, was that the proposed route best met the essential criteria set down and was therefore the best choice of all the ones considered.

4.2 The Interveners' Views

The Jacksons objected to the applicant's pipelines being located some 350 to 400 feet inside their property, thereby resulting in a severance of their land for approximately one-half mile. Their suggested alternative was to locate the proposed pipelines adjacent to the west property line.

Genstar was opposed to proliferation of rights of way across its property, and the possible effect this would have on the planned expansion of its industrial plant. While it had no viable alternative route to suggest, Genstar explored a number of possible solutions with the applicant, ranging from extension of the pipeline tunnel and/or casings, to the vertical stacking of pipelines across the property.

Prinz von Thurn took exception to the fact that Shell had followed a so-called "corridor route", when other alternatives existed which could be used. Counsel for Prinz von Thurn believed that these alternatives had not been fully explored, and that Shell was far from complete in its negotiations with landowners along its preferred route.

4.3 The Board's Views

In addition to some general concerns about route brought out in the course of the hearing, the Board is aware of a number of special concerns raised by interveners, resulting in part from the applicant's choice of route, that must be taken into account in the Board's decision. These relate to impacts resulting from special circumstances of three interveners, and are discussed in detail in sections 5 and 6 of this report.

Concerning the so-called "corridor route" for the applicant's proposed pipelines, the Board believes that the criteria selected by Shell with which to establish an optimum route meet with many of the standards expressed by the Board in the past. In addition to normal land use and environmental criteria, the Board has, on numerous occasions, supported the principle of making maximum effective use of land parallelling established linear disturbances (roads, railways, power transmission lines, pipelines), and minimizing the length of new rights of way across previously undisturbed land. In addition, the Board is strongly in favour of pipeline routes that will avoid, wherever possible, conflict with existing or planned urban development.

The Board believes that the applicant has, in large measure, met many of the Board's concerns in these matters, and that the applied-for route stands on its own merits independent of any possible "corridor" that may or may not be declared. The Board is satisfied that the proposed route maximizes use of land parallelling existing linear disturbances and use of existing Restricted Development Areas. It also avoids areas where the most substantial urban development can be expected and is acceptable from a safety and environmental viewpoint. It has an economic advantage over most other feasible routes, whereas none of the alternative routes investigated by the applicant offer significant offsetting advantages over the one proposed.

The Board recognizes the Jackson's continuing problem regarding the location of pipelines 350 feet from the west fence line of their property, and addressed the matter in some detail in an earlier decision report[6]. As stated in that report, it is important from a safety

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6 Energy Resources Conservation Board, 1982. Applications by Alberta Energy Company Ltd. for Permits to Construct Oil Pipelines in the Northeast Edmonton Area. ERCB Decision Report 82-6, Calgary, Alberta.

and construction standpoint that pipelines built subsequent to the initial AEC lines remain parallel and close together throughout, and do not cross at turning points. Since Shell undertook to provide proper access during construction, to bury all pipelines to a depth sufficient to avoid interference with farming operations, and to locate above-ground installations adjacent to the fence line, the adverse effect of the locations should be substantially alleviated.

With respect to Genstar's objections regarding pipeline rights of way across its property, the Board notes from Shell's testimony that Shell plans to share AEC's tunnel on the Genstar property, and to restrict the width of the remaining portion of the right of way above ground to 5 metres adjacent to the AEC right of way. It appears to the Board that this is a reasonable proposal for a route across the Genstar property, and minimizes the impact that the pipelines could have on Genstar's planned expansion. Matters of safety and spacing regarding the applicant's proposal at this location are discussed in section 6 of this report.

On the matter raised by counsel for Prinz von Thurn concerning the number of landowners affected by the applicant's proposed pipeline route and the lack of agreements, the Board notes that out of some eighteen landowners listed only three appeared at the hearing to object to the route. This indicates to the Board that the route is not a major issue with the majority of landowners involved, and consequently the Board does not, for purposes of this decision, attach significant weight to the apparent lack of formal landowner agreements.

5 SPECIAL MATTERS RAISED AT THE HEARING

5.1 Genstar

Genstar expressed a number of concerns relating to pipeline right of way spacing, and the effect this would have on its property. Should Shell's proposed 5-metre right of way be approved, and with the possibility of future rights of way in the same area, Genstar stated that its land would be extremely difficult to develop for future plant expansion. Additionally, Genstar indicated that the flaring-out of pipelines from the AEC tunnel into their respective rights of way would greatly increase the problem, as subsequent tunnels would necessitate a wider right of way. Genstar pursued the possibility of shared rights of way and closer pipeline spacing, suggesting that this would be feasible if the pipelines were cased throughout the Genstar property (see section 6.1).

In its submission, Genstar also proposed that any permit granted by the Board to Shell for pipelines across Genstar property should stipulate that Shell acquire the interest in such lands by negotiation with the owner.

In response to these concerns, Shell stated that shared rights of way would not be practical in this particular situation. The reasons cited included safety of the pipelines, cathodic protection problems, and additional expenses that would be incurred. Shell claimed that it was in the public interest for the Shell and AEC lines to be separated, and that AEC was in favour of a separation distance. Shell also contended that Genstar's concerns in relation to tunnel spacing were somewhat hypothetical, as there was no firm evidence to date to indicate the number of future pipelines that the existing AEC tunnel will accommodate.

Finally, Shell indicated that Genstar's plant location is within an area designated by Alberta Environment as a transportation and utility corridor, and therefore many of the concerns expressed by Genstar were normal consequences of such a corridor declaration.

The Board does not believe that Shell's proposed 5-metre wide right of way from the tunnel exit north across the Genstar property is excessive when the engineering constraints of exiting from the tunnel are taken into account. For the same reasons, it appears that sharing AEC's right of way would be impractical. The Board is of the opinion that Genstar, knowing that a designated RDA passes through its property, is faced with taking this into account when planning plant expansion or locating its future buildings or foundations. The Board expects that close consultation with the pipeline management committee will be mandatory in this type of planning, but believes that solutions can be worked out to take into account not only existing pipeline rights of way but also the area that could be involved for future lines. To the extent this is not possible, presumably compensation would be available to Genstar.

The Board does not concur with Genstar's request that Shell acquire an interest in the Genstar land by negotiation with the owner. One test of the validity for this type of request is that a unique situation must be shown to exist, and the Board does not believe that Genstar's situation differs substantially from other industrial sites faced with expansion around pipelines. Additionally, the Board believes that the pipeline facilities in question must be of a nature that are not in the "broad public interest" before it would require direct negotiation with the landowner. As stated earlier, the Board considers the proposed Shell pipeline to be in the public interest. Accordingly, the Board is not prepared to invoke section 11(2) of the Pipeline Act.

5.2 The Jacksons

The Jacksons stated that previous right of way reclamation on their land was less than adequate, resulting in poor topsoil conservation. Because of this, they were seeking assurances from Shell that the reclamation procedures outlined in its application would be followed. They also pointed out that a berm area enclosing 35 acres of their property had

been damaged by previous pipeline construction, resulting in flooding of their land. Again, they were looking for some assurance from Shell that this situation would not recur.

The Jacksons reiterated their preference that the Shell pipelines on their land be directly adjacent to property lines, but stated that if this was not possible, assurances were needed that Shell would provide access to the severance area between the property line and the construction. They also wanted some commitment that no above-ground appurtenances, such as the block valve proposed by Shell, would affect their farming operations.

Their final concern was that the proposed pipeline would cross sludge test plots established by Alberta Environment's Earth Science Division. The Jacksons said they had an obligation to preserve these plots, and requested Shell to avoid these sites but, if this was not possible, to avoid deviations from route in this area that would cause further damage.

Shell summarized its procedures regarding right of way reclamation, including proposed methods of topsoil conservation. Commitments had been made to Alberta Environment that an evironmental inspector would be present on the construction spread. With regard to the Jacksons' concern about flooding, Shell indicated that precautions would be taken to ensure that the earth berm across the Jacksons' land would not be damaged.

Concerning its lines adjacent to the existing AEC pipelines, Shell claimed that a "dead-zone" between rights of way would be created if the proposed pipeline was constructed on the west edge of the Jackson property. If Shell's location was accepted, temporary access to the severance area would be provided during the course of construction.

Regarding above-ground appurtenances, Shell confirmed that the only installation of this type on the Jackson property would be cathodic protection test posts at the property line. Shell also agreed to accommodate, to the best extent possible, the Jacksons' concerns about damage to the sludge test plots. Continuing discussions and liaison with Alberta Environment were promised.

The Board shares the same concerns with the Jacksons regarding proper topsoil conservation methods, and believes that only by careful adherence to proper conservation principles plus constant inspection during construction by an accredited environmental and/or soils expert, can these aims be achieved. The Board accepts Shell's undertaking to follow the reclamation procedures outlined in the application, and expects that proper inspection would be part of these procedures. The Board also accepts Shell's undertaking not to disturb the earth berm across the Jacksons' land.

The Board understands and is sympathetic to the problem raised by the Jacksons concerning the Shell pipelines located some 350 feet from the west fenceline of their property. It believes, however, as was stated earlier, that such placement is in the best long-term interests for minimum land fragmentation. Provided that proper access to the land is allowed for during construction as was promised by Shell, the effects on farming operations should be minimal.

The Board notes that Shell has no plans to locate above-ground appurtenances inside the Jacksons' property, and that cathodic test-lead posts would be at the property line. This should avoid interference with farming.

The Board agrees that the sludge test plots should be avoided if at all possible and, as in the case of soil reclamation procedures, the Board would expect Shell to provide adequate inspection during construction to avoid interference with the purpose of the plots or damage to the area.

5.3 Prinz von Thurn

Counsel contended that the Expropriation Act and especially the Surface Rights Act worked against his client's interests, and that the Board should allow his client to negotiate separately with Shell. Section 11(2) of the Pipeline Act was cited as the appropriate vehicle to allow such negotiation, and counsel requested the Board to invoke this part of the statute on behalf of his client. He also argued that because a number of conditions and agreements with certain parties such as landowners and government agencies had not been completed, the project should be delayed until all such agreements had been reached.

On the subject of land acquisition, Shell maintained that it had the right to expropriate, and that rulings under section 11(2) of the Pipeline Act should be reserved for special circumstances. No such circumstances had been brought out in evidence, and Shell submitted that it would not be in the public interest to invoke such a ruling. Also, in Shell's view, to require that all agreements and government approvals be completed prior to entering a hearing would be tantamount to the Board rubber-stamping applications that came before it.

The Board agrees with Shell that no evidence was brought forward to show that unusual circumstances in the public interest are involved in the request to invoke section 11(2) of the Pipeline Act. Accordingly, the Board is not prepared to accede to this request.

Concerning the matter of delaying the Shell project because of lack of completed agreements and arrangements, the Board believes that this is an unreasonable request. Every matter that comes before the Board has a multiplicity of uncompleted arrangements and agreements inherent in the application, and if the Board made it conditional that these be finalized prior to every hearing, lengthy and unnecessary delays would result.

6 TECHNICAL DESIGN, SAFETY, AND CORRIDOR-RELATED MATTERS

6.1 Technical Design

On the matter of technical design, the applicant stated that it intended to follow CSA Standard Z183-1977, "Oil Pipeline Transportation Systems", and the requirements of the Pipeline Act and Regulations.

Genstar raised the issue of casing the entire length of lines across its property in order to reduce the width of right of way needed, and Shell went into considerable detail to explain the technical problems and hazards associated with such a proposal. A similar discussion took place regarding the technical feasibility of "stacking" lines one above the other, and Shell's consultant pointed out the maintenance problems that could result from such a design.

The Board has reviewed the overall pipeline design submitted by the applicant, and is satisfied that it complies with the applicable standards, and with the requirements of the Pipeline Act and Regulations. The Board agrees with the applicant that it is not technically sound to case the pipelines outside the tunnel, nor is it practical from a maintenance point of view to stack the pipelines vertically in a single right of way.

6.2 Safety

Shell's application and subsequent testimony described a number of safety measures to be incorporated in the design and operation of the proposed pipeline system. From a design standpoint, the applicant believed that a 7.5-metre spacing from the NUL gas line would be optimum to avoid blast damage in the event of a rupture. A depth of cover of 1.2 metres would be maintained throughout, thus providing some additional protection from external damage. From an operating point of view, numerous safeguards would be built into the measurement and leak detection system, and a contingency plan would be drawn up for oil spill containment and emergency response. Pipeline surveillance procedures were also to be worked out with the other pipeline companies operating adjacent lines (AEC and NUL).

The Board is satisfied that the applicant has included adequate safeguards in its proposed design and operating procedures, and that the basic safety matters have been addressed. The Board is not entirely convinced from the evidence presented that 7.5 metres is the optimum distance for spacing from a gas pipeline to avoid rupture damage. Much of the information was graphical in nature, and no specific incidents of a rupture due to blast effects from an adjacent pipeline were cited.

However, the matter of optimum spacing from the NUL line has been discussed in a previous decision report[7], and the Board is prepared to accept the 7.5-metre spacing and 5-metre wide right of way requested by the applicant in the possible corridor.

6.3 Corridor-Related Matters

Shell stated that it had held discussions with both NUL and AEC regarding management of the proposed corridor. The talks had been preliminary in nature, but had centred around the need for joint surveillance procedures, leak detection, and construction schedules. The use of the pipeline tunnels had also come under discussion, and since these tunnels were built and under the control of AEC, matters of joint usage had been considered.

Notwithstanding the fact that no official corridor existed at the time of the hearing, the Board believes that the issues raised concerning a joint management group of pipeline operators is essential. Whether a corridor is declared or not, there are mutual design, operating, and maintenance problems relating to closely spaced pipelines to warrant careful consultation among the owners regarding these matters. The Board continues to believe that if a corridor is declared, total acquisition of all lands by either industry or government is desirable. This viewpoint has been expressed by the Board in a number of recent decision reports where this matter has been an issue, and the reasons have been documented.

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7 Energy Resources Conservation Board, 1982. Application by Northwestern Utilities Limited for a Permit to Construct a Gas Line in the Northeast Edmonton Area. ERCB Decision Report 82-22, Calgary, Alberta.

7 DECISION

The Board approves Application 820114 of Shell Canada Limited for pipelines more properly described in the application. The appropriate permit to construct will be issued in due course, subject to the approvals of the Minister of the Environment in matters of the environment and Restricted Development Areas.

ISSUED AT Calgary, Alberta on 12 July 1982.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

V E Bohme

V. E. Bohme, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary, Alberta

BIEWAG ENERGY RESOURCES LTD.
INDUSTRIAL DEVELOPMENT PERMIT
MANUFACTURE OF METHANOL FROM GAS

Decision 82-29
Application 820498

1 INTRODUCTION

1.1 Application and Hearing

Biewag Energy Resources Ltd. (Biewag) applied pursuant to section 30 of the Oil and Gas Conservation Act (the Act) for an Industrial Development Permit authorizing the use of natural gas as raw material and fuel for production of fuel-grade methanol at a new plant to be constructed in the County of Lamont, approximately 7 kilometres south of the Village of Waskatenau. The requested permit would authorize the annual use of 1800×10^6 m^3 of gas in the production of 1.65×10^6 tonnes of methanol per year. The gas would be obtained from Alberta sources, and the methanol would be exported from Canada.

A permit term of 20 years, commencing with plant start-up projected for early 1985, was requested.

A hearing of the application was held in Lamont, Alberta on 20 and 21 July 1982, with V. Millard, N. Berkowitz, P.Eng., and N. Strom, P.Eng., of the Energy Resources Conservation Board sitting.

Those who appeared at the hearing or filed submissions respecting the application are listed in Table 1.

1.2 Background

Biewag was formed as an operating company by Biewag Finanzierungsgellschaft Aktiengesellschaft, Koenigstein/Taunus (Biewag 1862), headquartered in Koenigstein, West Germany. Biewag 1862 would be wholly responsible for financing construction of the proposed methanol plant, and would lease the plant on a long-term basis to Biewag, which would operate it and market the methanol. Process engineering would be completed by a German engineering contractor, UDHE GmbH; but detailed engineering design, procurement and construction would be contracted to Alberta-based companies.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Biewag Energy Resources Ltd. (Biewag) J. R. Smith	J. I. Meyer T. W. Glasmacher M. Zelensky, P.Eng. G. L. Brown D. H. Boyd
The Village of Waskatenau E. J. Walter	E. J. Walter
R.O.M. Construction Ltd. (R.O.M.) D. Gremble R. Mangold	D. Gremble R. Mangold
Celanese Canada Inc. (Celanese) J. J. Marshall	J. K. Lambie, P.Eng.
Novacor Chemicals Ltd. (Novacor) H. D. Williamson	G. B. Hegeman of Arthur D. Little of Canada, Limited
Alberta Gas Chemicals Ltd. (AGCL) J. C. Major, Q.C.	
E. Krill	E. Krill
Ocelot Industries Ltd. (Ocelot) J. I. Parker	
Energy Resources Conservation Board staff D. Holgate, Board Solicitor R. Houlihan, P.Eng. D. Mulrain A. Nixon M. Mumby C. McKay	

1.3 Interventions

The Towns of Lamont and Bruderheim, R.O.M. and the Village of Waskatenau supported the project, but the latter two interveners believed that it would generate a greater population influx into Waskatenau than Biewag's application forecasts. The Towns of Lamont and Bruderheim did not send representatives to the hearing.

Two landowners near the proposed plant site opposed the project. A. Shumansky stated in his written intervention that the plant would interfere with his life style. E. Krill appeared at the hearing and expressed concern that land drainage problems might be aggravated by the plant.

Celanese and AGCL, both producers of methanol in Alberta, opposed the project on the grounds that the application contained insufficient information on ownership and control, proposed markets, annual natural gas requirements and project viability. AGCL withdrew its opposition to the project after Biewag indicated that it would accept a clause in any permit that might be issued effectively requiring dispositon of the methanol in new markets not presently served by existing Alberta methanol producers.

Novacor presented evidence respecting the economic viability of methanol end uses from a consumer standpoint. Dow filed an intervention for the purpose of cross-examination and argument, but did not appear at the hearing.

Ocelot intervened for the purpose of cross-examination and argument, and expressed concerns regarding a potential oversupply of methanol in markets served by current western Canadian methanol producers.

2 ISSUES

In considering the application, the Board considers the principal issues to be

(a) the efficient use of energy resources,

(b) the present and future availability of natural gas in Alberta,

(c) markets for the methanol to be produced,

(d) the impact of the project on the Alberta economy and on methanol plants currently operating in Alberta,

(e) permit term and gas volumes,

(f) social impact,

(g) environmental impact.

3 THE EFFICIENT USE OF ENERGY RESOURCES

3.1 Suitability of Gas as Feedstock and Fuel in the Manufacture of Methanol

In support of its choice of natural gas as feedstock and fuel for the proposed methanol plant, Biewag submitted that it had considered coal as an alternative, but found it economically unacceptable for its purposes.

The Board agrees that current Alberta conditions favour gas as a feedstock and fuel for a methanol plant scheduled to begin operations in 1985.

3.2 Efficient Use of Gas

The plant proposed by Biewag would use the Imperial Chemical Industries (ICI) low-pressure process. Process steps include feedstock and fuel desulphurization, steam reforming, compression, methanol synthesis and product purification. Basic engineering design would maximize waste-heat recovery throughout the plant; and overall energy efficiency in terms of the higher heating values of feedstock, fuel, and methanol, including electric energy producible within the plant, would be 62.8 per cent.

The Board notes that total energy consumption could be significantly reduced if off-site CO_2 were used to adjust the carbon/hydrogen ratio of synthesis gas, but agrees that this is only feasible where a low-cost supply of CO_2 is available. The Board would require Biewag to use such offsite CO_2 if it became practical in the future.

Since Biewag proposes to produce fuel-grade methanol, the Board also agrees that the additional capital and operating costs associated with a 4-stage distillation unit would not be justified.

Overall, the Board is satisfied that the plant would be designed to utilize appropriate energy-efficient processes and equipment.

4 PRESENT AND FUTURE AVAILABILITY OF NATURAL GAS IN ALBERTA

Biewag's total gas requirement would be 36×10^9 m^3 if the applied-for 20-year permit term were granted. This volume would represent approximately 1.9 per cent of Alberta's total remaining established reserves of natural gas. Biewag stated that all of the gas would be supplied by Northwestern Utilities Limited who would also install the necessary transportation facilities.

The Board believes that sufficient gas will be available in Alberta for the proposed use over the requested permit term, but would require Biewag to satisfy it with respect to definite arrangements for the supply of gas.

5 MARKETS FOR THE METHANOL TO BE PRODUCED

5.1 Views of Biewag

Biewag agreed with interveners "that the chemical market cannot bear another 1.5 million tonnes per year (of) production without harming existing Alberta producers". However, Biewag pointed out that its proposed plant would pose no threat to other methanol producers in Alberta and Canada since it had secured an energy-related market for its total output. For business reasons Biewag declined to reveal the identity of its customer, but was prepared to accept a permit that would, in effect, preclude disposition of its methanol in markets presently served by existing Canadian producers.

To further alleviate concerns respecting its impact on existing methanol markets Biewag also stated at the hearing, among other matters relating to the contract, that it has negotiated "a single contract", "with one party" and that the contract "is a full 15-year commitment". It also observed that it has "gone to great lengths to avoid interfering with or approaching any customer of any existing Alberta and/or Canadian producer, nor do we (Biewag) have any intention of doing so in the future". Biewag noted as well that its customer "is the end user of the product as fuel" and that "they take the output of the plant, whether they need it or not".

5.2 Views of the Interveners

Celanese introduced evidence regarding European methanol markets and expressed doubt that fuel-grade methanol markets could absorb the output of the proposed plant. Without assurances respecting the existence of a new market, Celanese was not satisfied that output from the proposed plant would not displace existing Alberta productive capacity.

Novacor stated that it would not oppose a new plant that would stimulate development of new export markets for fuel-grade methanol. Novacor believed, however, that the existence of such a market must be demonstrated and that it must be established that Biewag's output was irrevocably committed to that market. Novacor observed that the applicant's contract with its customer would not appear to restrict the end use of the methanol, and expressed concern that a portion of Biewag's production might therefore, at some time, enter the chemical market. It submitted that the dumping of a large volume of methanol in the chemical market would have a disastrous impact, and that it would support the proposed project only if assured that this will not occur over the life of the permit.

AGCL expressed a similar concern, but withdrew its intervention after Biewag said that it would accept a permit that prevented it from entering markets in which it would compete against existing Canadian methanol producers.

Ocelot reiterated the view of certain other interveners that the proposed markets appear highly speculative, and that output from the applicant's proposed plant could potentially disrupt markets for chemical-grade methanol.

5.3 Views of the Board

The Board agrees that, because of proprietary interests, the applicant should not be required to file a copy of its contract as part of the public record. It does, however, share interveners' concerns that a volume of methanol such as that which Biewag proposes to produce could jeopardize the existing markets of Alberta methanol producers, especially if it became available as chemical-grade product. The Board accepts Biewag's evidence that it has a contract for the sale of fuel-grade methanol only and that the market is incremental to those served by existing Canadian productive capacity. In view of the currently very limited use of methanol as a fuel for transportation or power generation, yet the apparent environmental advantages to be expected from such use, the Board also suspects that any large-scale infusion of fuel-grade methanol to a new market of this type may enhance future overall sales prospects of existing producers. The Board believes it significant that Biewag is prepared to accept a permit condition in the form requested by AGCL, and that AGCL was sufficiently satisfied with such a condition that it withdrew its intervention.

Clearly, the most significant aspect of the application is the nature of Biewag's contract with its customer. In considering the applicant's statements regarding this matter (as discussed in section 5.1) and other

relevant evidence presented at the hearing, the Board has attempted to define the contract conditions as it understands them. In general the contract described by Biewag would affirm that

- total plant output is contracted to a single European purchaser;
- the contract is for fuel-grade methanol only;
- the market created by the purchaser does not diminish sales opportunities for existing Alberta and, indeed, Canadian productive capacity;
- the purchaser is the end user of the plant product;
- the contract is negotiated on a take-or-pay basis; and
- the contract term is 15 years.

The Board believes that any entry of Biewag's methanol into the chemical market or markets that might be supplied by other producers would be quickly identified, and that non-compliance with the permit condition would become obvious. Nevertheless, having regard for the unique nature of the contractual agreement, and the importance of that arrangement to other producers as well as to the Alberta public interest (as discussed in section 6), the Board believes a further safeguard to be warranted. Accordingly, a permit issued by the Board would contain a condition that a copy of the contract be filed on a confidential basis with the Minister of Economic Development prior to start of construction. Biewag's authority to exercise its rights under the terms and conditions of this permit would be subject to satisfying the Minister of Economic Development that the contract complies with the Board's understanding of the contract conditions.

6 IMPACT OF THE PROJECT ON THE ALBERTA ECONOMY AND METHANOL PLANTS CURRENTLY OPERATING IN ALBERTA

6.1 Views of Biewag

Expressing all its projections in 1982 dollars, Biewag estimated that methanol sales revenue will be $450 million annually, or approximately $9 billion over the requested 20-year permit term. The project was estimated to generate $626 million in corporate taxes and to provide an after-tax net income of $884 million.

Using a conventional multiplier of two, Biewag estimated the direct and indirect impact in Alberta to be approximately $9.3 billion. This calculation incorporates the Alberta portion of capital investment, and operating expenditures, including fuel and feedstock costs, and taxes.

6.2 Views of Interveners

The Village of Waskatenau and R.O.M. supported the application on the grounds that the plant would provide a very favourable economic stimulus for the general area.

Celanese stated that the project must be economically viable to be in the public interest of the province. If the sales contract for a market not presently served by Alberta producers exists, no negative impact was perceived, but if output from the proposed facility entered chemical markets presently served by Alberta methanol producers, it would have a detrimental impact on them. Novacor and Ocelot expressed similar views.

6.3 Views of the Board

The Board shares concerns over the potential impact on methanol producers if output from the proposed facility entered chemical markets presently served by existing capacity, but notes the applicant's assurances and acceptance of the contract condition. In this light, the Board considers the proposed project to be in the Alberta public interest.

Based on the Board's assessment of the Alberta share of construction and operating costs, net income, and taxes, derived from the activities of Biewag 1862 and Biewag, the Board's estimate of the incremental direct impact of the proposed project on the Alberta economy* (Table 2) indicates a total of about $2 billion over the proposed 20-year life of the project. A multiplier of two was used to estimate a total direct and indirect impact on Alberta* of some $4 billion.

In its assessment of direct impact, the Board assumed that 39 per cent of capital costs and 65 per cent of operating costs would be spent in Alberta. Forty per cent of Biewag's net income would accrue to Canadians in proportion with equity participation. The Board assumed that 10 per cent of the Canadian participation in Biewag would be held by Albertans. Net income accruing to Alberta was therefore expected to equal 4 per cent of Biewag's total net income over the project's life. Tax revenues accruing to the province were assumed to equal 100 per cent of municipal and provincial payments and 10 per cent of federal payments.

The Board's forecasts* of net after-tax income over the project life are summarized in Table 3. The estimates are $1.85 billion and $0.82 billion for Biewag 1862 and Biewag, respectively. Evidence tendered by the applicant indicated that Biewag 1862 may not be subject to Canadian income taxes; and since Biewag 1862's position with respect to Canadian tax liabilities is ambiguous, the Board did not attribute federal or provincial income taxes to the company's earnings. This may result in an underestimate of tax receipts.

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* In 1982 dollars.

TABLE 2 INCREMENTAL ALBERTA IMPACT
(1982 dollars)

	BIEWAG 1862	BIEWAG ENERGY RESOURCES LTD.	TOTAL
Construction Costs	254	-	254
Operating Costs	-	1 330	1 330
Net Income	-	33	33
Taxes	-	327	327
Feedstock and Fuel	*	*	*
Total Direct Impact	254	1 690	1 944
Indirect Impact	254	1 690	1 944
Total Impact	508	3 380	3 888

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* Cost of gas feedstock is assumed to be Alberta border price or opportunity price of competitive seller in Alberta. Thus, there is no positive or negative effect on Alberta, provided the alternative market for the gas does exist.

TABLE 3 NET INCOME AFTER TAXES
(1982 dollars)

	BIEWAG 1862	BIEWAG ENERGY RESOURCES LTD.
Revenue	2 500	8 900
Expenditures		
Construction Costs	650	-
Operating Costs	-	2 060
Leasing Costs	-	2 500
Municipal Taxes	-	130
Feedstock and Fuel	-	2 800
Total Costs		7 490
Operating Income Before Tax	1 850	1 410
Income Taxes		
Provincial	-	155
Federal	-	423
Total Taxes	-	592
Net Income After Taxes	1 850	818

7 PERMIT TERM AND GAS VOLUMES

Biewag requested that the permit be issued for a term of 20 years, and that it authorize the use of 36×10^9 m^3 of natural gas as feedstock and fuel over that period.

In view of the 15-year sales contract which Biewag stated it had negotiated for sale of the plant product, the Board believes that a permit term of 15 years is appropriate. The total volume of natural gas that it would be prepared to approve for use by Biewag under terms and conditions of the permit would therefore be reduced to 27×10^9 m^3. This volume would represent approximately 1.5 per cent of Alberta's total remaining established reserves of natural gas. Upon application by Biewag, the permit term could be extended subject, among other considerations, to satisfying the Board that appropriate markets have been obtained.

8 SOCIAL IMPACT

Biewag estimated that the three-year construction phase of the project would generate approximately 1400 man-years of direct employment and an Alberta population increase of from 550 to 825. This assessment was based on calculations of direct, indirect and induced employment, and assumed that 20 to 30 per cent of the positions created would be filled by in-migrants. It also incorporates an appropriate employment/ population ratio for Alberta. The City of Edmonton was forecast to receive from 80 to 90 per cent of projected growth, although the applicant discussed the possibility of utilizing a construction camp that would reduce this impact by 10 to 20 per cent.

Operation of the plant would require approximately 150 full-time staff. Applying the same growth parameters as above to the construction phase, Biewag estimated the population increase for Alberta to total approximately 690 for plant operation. This estimate assumed that 50 per cent of all new jobs in the Edmonton and Fort Saskatchewan region would be filled by in-migrants, and that in-migrants would fill total employment generated in other communities.

In Biewag's assessment of population distribution among the regional communities, including Edmonton, two scenarios were presented. One, intended to describe the first three to four years of the operational phase, assumes that 70 per cent of the projected population increase would choose to reside in Fort Saskatchewan and Edmonton. The second, considered typical of the succeeding years of plant operation, suggests that 42 per cent of the population increase would reside in smaller communities, particularly Lamont and Bruderheim.

Both the Village of Waskatenau and R.O.M. contended that Waskatenau would experience substantially more population growth than outlined in Biewag's application. R.O.M. stated that Waskatenau is only seven kilometres from the proposed plant, and easily accessed by highway and railway services, and noted that town services could accommodate a substantial increase in population. It therefore believed that Waskatenau would attract at least 13 to 20 per cent of the plant employees rather than the 3 to 10 per cent suggested by Biewag, and that 70 to 80 per cent of all permanent employees would reside as close to the plant as possible if adequate housing were available.

The Board notes that plant construction personnel would be hired through union halls in Edmonton, and believes that population increases attributable to the construction phase would mainly accrue to that city. However, this increase is not expected to impose significant pressures on the City of Edmonton.

The Board recognizes the position of the interveners with respect to the potential population growth of smaller communities during the operation of the plant and agrees that, subject to availability of adequate housing and community infrastructure, most employees would choose to live as close to their place of work as possible.

9 ENVIRONMENTAL IMPACT

The total plant site, including buffer zone and shelter-belt, would comprise 65 hectares, but only 28 hectares would be directly affected by development and removed from agricultural use. Canada Land Inventory classes 1 to 3 soils occupy approximately 71 per cent of the area that would be developed. Approximately 4 hectares of land would be used for a construction camp if that alternative were chosen over busing workers to the site. Topsoil removed from this area would be redistributed and the area reclaimed for agricultural use following the construction period. Undeveloped portions of the site would also be leased for agricultural purposes. Topsoil would be stripped from the developed areas and used to landscape berms and, where possible, to upgrade agricultural lands of lower capability. Although the amount of topsoil available for these purposes remains to be determined in a detailed soil study, Biewag stated that highest priority in berm construction would be given to plant site boundaries facing major population areas to the north and south of the plant.

The North Saskatchewan River would be used as a source of raw water and would be the receiving stream for treated waste-water effluent. Water would be trucked to the site by a local contractor during the construction phase, and would be withdrawn from the river in compliance with the water diversion licence issued by Alberta Environment. All effluents discharged would meet the requirements of a licence issued under the Clean Water Act.

Biewag stated that air-quality changes would occur locally as a result of dispersion of nitrogen dioxide and carbon monoxide in stack emissions, and that fugitive emissions of methanol may also result from storage-tank breathing losses. Modern process technologies and emission controls as well as monitoring systems, would be used to ensure that ground-level concentrations of potential atmospheric pollutants are maintained well below Alberta Clean Air Act objectives.

Average noise levels due to plant operation would also remain within provincial objectives. Biewag contended that the construction of berms, shelter-belt planting, and suitably designed buildings containing noisy equipment would assist in achieving these objectives. Appropriate procedures and processes would ensure safe management of hazardous materials used or produced at the plant. Biewag would also develop contingency plans in cooperation with emergency services personnel of local communities to handle potentially dangerous situations.

E. Krill, who resides immediately south of the proposed plant, expressed concern that, due to the possibility of the plant site's being slightly elevated, his land may be adversely affected by drainage patterns. Biewag stated that all water-related site drainage problems would be addressed in order to comply with its permit under the Clean Water Act.

In view of the concerns expressed by Krill, and Biewag's response to this matter, the Board is satisfied that the plant would not create or aggravate drainage problems.

The Board accepts the applicant's commitment to operate within established provincial environmental standards and objectives, but recommends that Biewag have an emergency contingency plan in place before plant start-up, and that relevant procedures be effectively communicated to local residents.

10 DECISION

Having regard for its responsibilities under section 30 of the Oil and Gas Conservation Act, and subject to the applicant's filing with the Minister of Economic Development, on a confidential basis, an executed copy of its sales contract, and satisfying the Minister that the terms of the contract reflect the Board's understanding thereof, as outlined in Section 5.3 of its Decision Report, the Board is prepared, with the authorization of the Minister of Economic Development and the Lieutenant Governor in Council, to grant the application. The term would be as shown in the appended document and subject to all terms and conditions therein.

DATED at Calgary, Alberta, on 1 October 1982.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

N. Berkowitz, P.Eng.
Vice-Chairman

N. Strom, P.Eng.
Board Member

FORM OF PERMIT

IN THE MATTER of the Oil and Gas Conservation Act, being chapter 0-5 of the Revised Statutes of Alberta, 1980; and

IN THE MATTER of an industrial development permit to Biewag Energy Resources Ltd. authorizing the use within Alberta of gas produced in Alberta for the production of methanol

INDUSTRIAL DEVELOPMENT PERMIT NO. BER 82-5

WHEREAS Biewag Energy Resources Ltd. has applied to the Energy Resources Conservation Board for an industrial development permit, pursuant to section 30 of the Oil and Gas Conservation Act, authorizing the use of gas produced in Alberta for the production of methanol in Alberta; and

WHEREAS the Board, upon inquiry into the application, is of the opinion that the granting of this industrial development permit for the use of gas as raw material and fuel in the production of methanol is in the public interest having regard to, among other considerations, the efficient use without waste of energy resources and the present and future availability of hydrocarbons in Alberta; and

WHEREAS the Lieutenant Governor in Council, by Order in Council, numbered O.C. and dated has authorized the granting of the permit.

THEREFORE, the Energy Resources Conservation Board, pursuant to the provisions of section 30 of the Oil and Gas Conservation Act, being chapter O-5 of the Revised Statutes of Alberta, 1980, hereby grants an industrial development permit to Biewag Energy Resources Ltd. (hereinafter called "the Permittee") authorizing the use of gas as raw material and fuel in the production of methanol, subject to the regulations and orders made pursuant to the said Act and to the terms and conditions prescribed in this permit as follows:

1. Prior to commencement of construction the applicant shall provide an executed copy of its sales contract to the Minister of Economic Development, in confidence, and shall satisfy the Minister that the particulars of the contract provided by the applicant and set out in clause 5.3 of the Board's decision report meet the Board's understanding of the contract.

2. The plant facilities at which methanol will be produced shall be located in the northwest quarter of Section 22, Township 58, Range 19, West of the 4th Meridian.

3. This permit is for the use by the Permittee of gas as raw material and fuel in the production of approximately 1 650 000 tonnes per year of methanol, generally as described in the application dated May 1982.

4. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be for a term commencing on the date hereof and ending on December 31, 2000.

5. The quantity of gas that may be used in the industrial operation referred to herein shall not exceed

(a) 1746×10^6 cubic metres per calendar year as raw material and 54×10^6 cubic metres per calendar year as fuel, or

(b) 27×10^9 cubic metres during the term of the permit referred to in clause 4.

6. The quantities of gas for the purpose of this permit shall be on the basis of a gas free of water vapour and having a higher heating value of 37.4 megajoules per cubic metre.

7. All gas used in producing methanol pursuant to this permit shall be measured by or on behalf of the Permittee in a manner satisfactory to the Board, and the volumes of gas used as raw material and fuel and methanol produced shall be separately reported to the Board in a manner satisfactory to the Board.

8. The Permittee shall satisfy the Board prior to as to the arrangements that have been made for the supply of gas for the operation of its plant unless, upon application by the Permittee a later date is stipulated by the Board.

9. The Permittee shall obtain the approval of the Board of any major changes in design of the plant facilities.

10. The Permittee shall satisfy the Board prior to that construction of its proposed project has commenced and that construction of the proposed facilities will continue in accordance with a schedule approved by the Board.

11. During construction of the proposed project, the Permittee shall inform the Board on a semi-annual basis, of the progress of construction.

12. The Permittee shall operate the facilities in a manner that results in

(a) the maximum practicably obtainable efficiency in the use of gas for the manufacture of methanol, and

(b) the maximum practical conservation of gas.

13. The Permittee shall not

(a) assign this permit, or

(b) release from his control the operation of the plant,

without consent in writing of the Board, which may, with the authorization of the Lieutenant Governor in Council, be given by the Board upon application therefor.

14. (1) Attached hereto as Appendix A and made part of this permit, is the order of the Lieutenant Governor in Council authorizing the granting of this permit.

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

THE CITY OF EDMONTON
240/14.4-kV SUBSTATION
CASTLE DOWNS

Decision 82-31
Application 810899

1 THE APPLICATION AND HEARING

The City of Edmonton (Edmonton Power) applied pursuant to sections 12, 14, and 17 of the Hydro and Electric Energy Act for a permit and licence to construct and operate a 240/14.4-kV substation in the Castle Downs area of The City of Edmonton (see Figure 1). Edmonton Power also applied for an order to connect the proposed substation to TransAlta Utilities Corporation's (TransAlta's) 240-kV transmission line CP 920L.

A public hearing to consider the application was held by the Energy Resources Conservation Board on 24 and 25 June 1982 in Edmonton, with C. J. Goodman, P.Eng., R. G. Evans, P.Eng., and T. F. Homeniuk, P.Eng., sitting. The following table lists the parties who appeared at the hearing.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
The City of Edmonton (Edmonton Power) D. Davidson A. Massing	E. Kyte, P.Eng. D. Pelletier, P.Eng. T. Loat A. Davies, P.Eng.
Homestead Holdings et al (Homestead) L. A. Desrochers F. Slater	G. Maxwell, P.Eng. W. R. Cheriton, P.Eng. R. S. Trussler, P.Eng. L. O. Spencer J. R. Andrew
Energy Resources Conservation Board staff D. Holgate K. Kendrick M. MacRae T. Y. K. Chan, P.Eng.	

Mrs. L. Brown of the Baturyn Community League, D. McCafferty of the Lorelli Community League, and M. Gregory made written submissions to the Board but did not appear at the hearing. The submissions were introduced at the hearing by Mr. Desrochers.

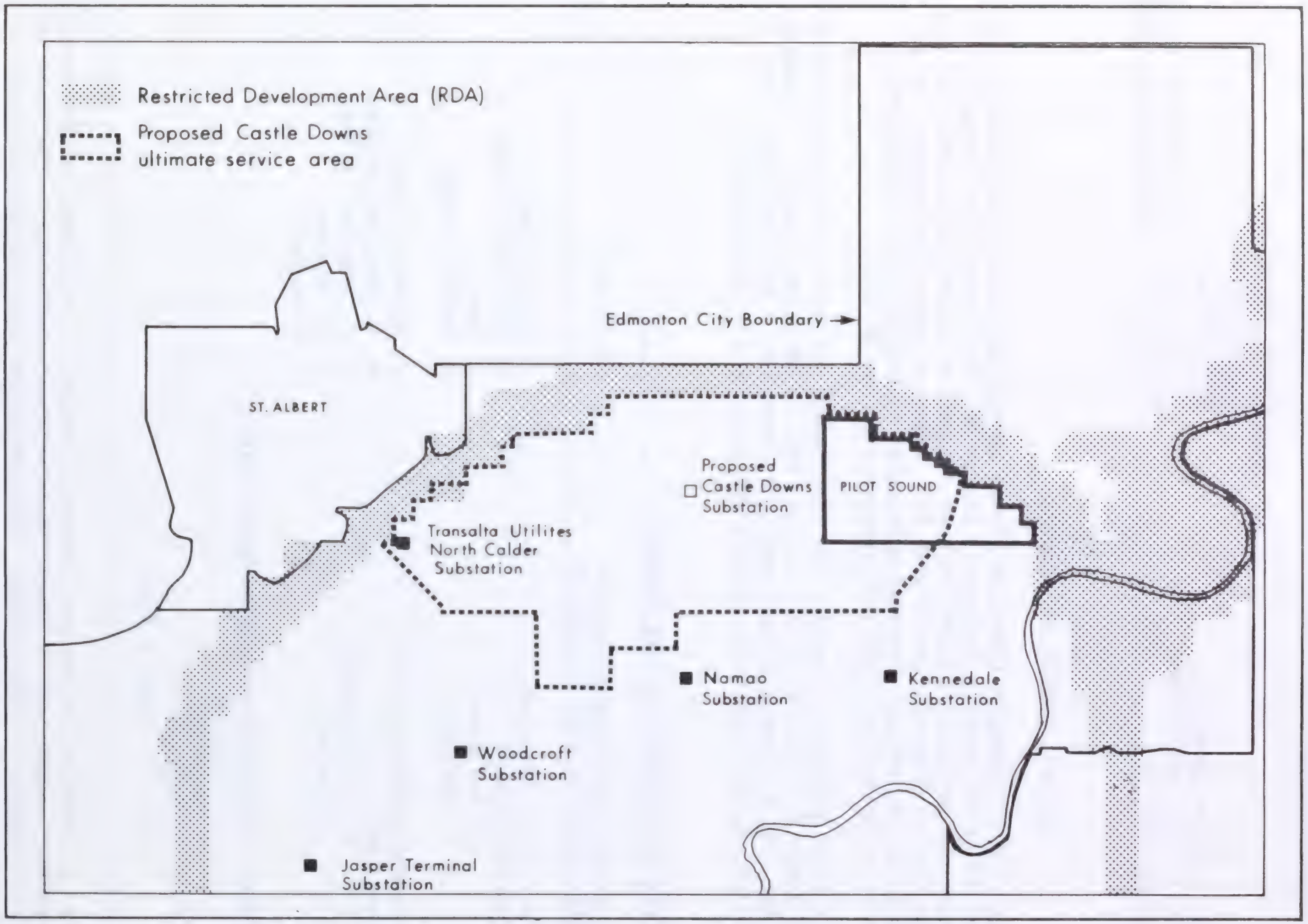

FIGURE 1 NORTH EDMONTON

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

2 DEFINITION OF THE ISSUES

The Board considers the issues to be:

- o the need for the substation;
- o public safety;
- o the location of the substation; and
- o the design of the substation.

3 THE NEED FOR THE SUBSTATION

3.1 The Need For More Distribution Facilities in North Edmonton

3.1.1 Views of the Applicant

Edmonton Power stated that residential growth has been occurring in north-central Edmonton. The electricity demand for the area, including Castle Downs, is forecast to be approximately 30 MVA in 1983, increasing to 60 MVA in 1985 and 153 MVA by 1993. The area is presently supplied from the Kennedale and Namao substations. However, these substations will be fully loaded in 1982, hence more substation capacity will be required to meet the expected 1983/84 peak load.

Edmonton Power stated that its forecasts included the electric energy demands of all sectors of the economy. It acknowledged that the present economic downturn would have some short-term negative effect on residential and commercial development in the city. However, it contended that industrial development, occurring in and around Edmonton, would contribute to the long-term growth of Edmonton.

Edmonton Power stated that Edmonton City Council has adopted an urban growth strategy to approve new development closer to existing development, fill in those vacant lands enclosed by the Restricted Development Area (RDA), and develop those lands immediately outside the RDA. This strategy suggests that north Edmonton is slated for further expansion.

To initiate development in north Edmonton, City Council has approved an Area Structure Plan for the Pilot Sound area west of 66th Street and north of 153rd Avenue. It has also authorized the preparation of an Area Structure Plan for northwest Edmonton. Both areas are expected to be developed primarily into residential neighbourhoods.

3.1.2 Views of the Board

The Board has reviewed the evidence submitted and is satisfied that expected urban development in north Edmonton will require more substation capacity to supply distribution loads in the area.

3.2 Alternative Methods of Providing Substation Capacity to North Edmonton

3.2.1 Views of the Applicant

Edmonton Power submitted that it had completed a detailed analysis of the electricity needs of the entire north Edmonton area. As a result it proposed to construct a 240/14.4-kV, 170-MVA substation in the Castle Downs area adjacent to TransAlta's 240-kV transmission line CP 920L. The ultimate area served by the substation would cover approximately twenty square miles, bounded on the south by 137th Avenue, on the north by the northern city boundary, on the east by Manning Freeway, and on the west by St. Albert Trail. The substation would have sufficient capacity to meet the total electricity demand in the area.

In evaluating the cost of the substation, Edmonton Power conducted its economic analysis through to about 2005. It stated that to speculate on load growth much beyond this time frame was too uncertain a base on which to commit major capital expenditures at this time. The applicant rationalized its economic analysis and site evaluation by noting that its proposed development:

(1) would make maximum use of existing distribution facilities, particularly along 97th Street;

(2) would provide a reliable supply to the area and would relieve loading on substations presently supplying the Castle Downs area;

(3) would be closest to the expected load centre and would provide the lowest-cost distribution network; and

(4) would be the most flexible means of serving the area.

Edmonton Power stated the total cost of its proposal, accounting for the timing of expenditures, would be some $19.7 million.[1]

In evaluating the intervener's proposal for two substations to serve north Edmonton, the applicant stated that the intervener's evaluation time frame of 40 years for planning distribution facilities is too long.

Edmonton Power contended that its evaluation period of 20 years is more realistic and in keeping with 25-year forecasts compiled by the Electric Utility Planning Council (EUPC), which are used for planning generation, transmission, and distribution facilities.

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1 In 1982 dollars. The applicant assumed a 1982 reference date for its economic evaluation; the intervener assumed a 1983 reference date and that 1982 and 1983 dollars for its analysis were equivalent. The Board has not adjusted these economic evaluations to a common period. All references cited in this report are taken to represent 1983 dollars.

Edmonton Power estimated that the intervener's proposed alternative of two 85-MVA substations would cost $31.3 million, or some $11.6 million more than the proposed Castle Downs substation. The main reason for the difference is the distance from the alternative substation sites to the load centre in Castle Downs. The applicant advised that its cost figures reflect a marginal-cost analysis, in which costs common to the two alternatives are not reported, and that the alternatives become similar at about the 20-year horizon.

Edmonton Power asserted that the intervener's proposal would also entail other disadvantages: it ignored the existing load at Castle Downs, and other existing facilities within Edmonton Power's distribution system.

Summarizing its objections to the intervener's proposal, Edmonton Power stated that investing substantial sums of rate payers' money now in order to serve a highly uncertain demand some 20 to 40 years in the future was irrational planning. If Edmonton Power's predictions occur it stands to save some $11.6 million. If the intervener's predictions of load growth, and its locations, for the period 30 to 40 years hence occur, Edmonton Power stands to lose about $1.5 million by the intervener's calculations. Finally, Edmonton Power asserted that its proposal would enhance distribution flexibility. If its load projections were not exceeded, it could get by with one substation, whereas, it would be committed to two substations if it proceeded as proposed by the intervener.

3.2.2 Views of the Intervener

Homestead claimed that the application did not provide for the most economic, orderly, and efficient development of the electric distribution system in north Edmonton. It stated that the application presupposed the use of a single substation to serve the load area but did not provide any technical and planning reasons to explain why the single-substation format would be the most desirable or efficient means of distributing electric energy in north Edmonton. The intervener asserted that the applicant had single-mindedly pursued technical objectives in the design of the electrical distribution system, and had ignored planning, environmental, and social considerations of equal and perhaps greater importance. It believed that viable alternatives were open to the applicant and suggested that the applicant should demonstrate to the Board that the option chosen would be optimum when all the costs, not just the economic costs, were considered.

The intervener also stated that serving a district eight miles wide from east to west and twenty square miles in area at 15-kV would result in voltage regulation problems and excessive energy losses. These problems would increase because industrial areas of high load density are planned at the east and west extremities of the area, four miles from the proposed substation. The intervener submitted that planning for distribution facilities of the size proposed by the applicant should include consideration of the ultimate long-term power requirements of north Edmonton. It contended that Edmonton Power's planning horizon is unrealistic and inadequate.

The intervener submitted a detailed feasibility study comparing Edmonton Power's proposal with a two-substation concept. It said that, despite the

difficulties in projecting load for 30 to 40 years hence, a fair comparison of the two alternatives could only be achieved if the forecasts were extrapolated to the year when full development of north Edmonton would occur. Hence, it made studies with respect to population projections and industrial job trends for the entire north Edmonton area. It concluded that around the year 2020, full development in north Edmonton could be expected and the electric load within the defined area served by the proposed Castle Downs substation would be 213 MVA. The applicant's proposed substation would be unable to handle that ultimate load. The intervener argued that, since industrial load growth would be at the east and west extremities of the area, Edmonton Power would be forced to add an extra substation at each of these locations in order to avoid excessive voltage drop and power loss. The intervener, therefore, submitted that Edmonton Power's one-substation proposal would eventually lead to a three-substation configuration for north Edmonton.

Homestead's proposed substations would be located adjacent to TransAlta's 240-kV line right of way and in non-residential areas. One substation would be in the Pilot Sound area, just over 3 miles east of the proposed Castle Downs substation. The second would be near TransAlta's North Calder substation, about 3 miles west of the proposed Castle Downs substation. The intervener submitted that these sites would be suitably located with respect to both planning and power distribution.

The intervener indicated that lands in the Pilot Sound and northwest Edmonton areas are owned by the same interests. It claimed that because an Area Structure Plan for Pilot Sound had already been approved, whereas one for northwest Edmonton had not, the emphasis on development would be in northeast Edmonton. The intervener also noted that development in northwest Edmonton was surrounded by considerable conflict regarding land use. The intervener suggested that the northeast substation should therefore be constructed first to partially unload Namao substation and to cope with near-term load growth. This first substation and other existing substations in the same vicinity would be used to their full capacity, deferring the construction of the second substation in northwest Edmonton until sufficient load developed to warrant the capital expenditure. It also submitted that the two substations might be doubled in capacity later. The capacity of these substations could then be a partial or full solution to load growth in areas west of St. Albert Trail and the newly-annexed northeast area.

Costing out the alternatives over a 30- to 35-year term, and accounting for the timing of expenditures, Homestead's analysis showed that its proposal for two substations would cost approximately $33.93 million, some $1.16 million less than its estimate of $35.09 million for Edmonton Power's proposal. Using a period for cost evaluation comparable to that used by Edmonton Power, the intervener found the cost difference favoured the applicant's proposal by about $8.1 million.

The intervener argued that its proposal would eliminate the need to build substations in a residential neighbourhood, thus virtually eliminating "quality-of-life costs" associated with the applicant's proposal. It stated that health and safety considerations, together with the noise and aesthetic

problems created by the applicant's substation, would be a real and ongoing cost to the quality of life for residents of the area. It reasoned that these costs would be significantly reduced under its two-substation proposal where all substations would be sited on industrially zoned lands.

3.2.3 Views of the Board

The Board notes that the proposals of both the applicant and the intervener are based on similar forecasts of electric load growth in north Edmonton. Indeed, Homestead stated that it had based its load forecast on data obtained from Edmonton Power. The basic difference in the evaluation and comparison of the two proposals by Homestead and Edmonton Power is the time frame over which the forecasts were made.

The Board agrees with Homestead that a sufficiently long period of time should be used in such evaluations so that viable options to those immediately apparent are not precluded. It also accepts Edmonton Power's view that decisions to make major capital expenditures must be based on information that is both reasonable and practical, and in which there can be reasonable confidence or minimal uncertainty. The Board also believes that the proposals must be evaluated for technical viability, cost effectiveness, and flexibility to respond to changes in the pattern of development in north Edmonton.

The Board has considered the extent of the presently undeveloped north Edmonton area and, on the basis of the evidence of both Edmonton Power and the intervener, is of the view that there is considerable uncertainty as to how the area will be developed, and particularly as to when various portions of the area might be developed. This uncertainty increases as one projects into the future and, in the Board's view, is too great in the latter part of the 35-year forecast period used by Homestead. This uncertainty is not offset by the relatively small cost advantage claimed, even if all of the intervener's assumptions should eventually prove correct. The Board therefore accepts Edmonton Power's forecast period as being more reasonable and practical.

Based on a forecast period of some 20 years, Edmonton Power's cost evaluation of the two proposals shows that the single-substation alternative would cost some $11.6 million dollars less than the two-substation alternative. Homestead's comparative evaluation resulted in a difference of $8.1 million in favour of the single-substation alternative. Regardless of which 20-year evaluation is correct, the Board considers this difference to be significant and accepts that the single-substation alternative is more cost effective.

Homestead suggested that a single substation near the centre of the north Edmonton area would require large quantities of electricity to be fed over long distribution lines to serve the industrial loads some 4 miles away. It contended that distributing such quantities at 15 kV over long distances would lead to high power losses and voltage regulation problems. Homestead did not substantiate its contention and although the Board recognizes this as a potential problem it expects Edmonton Power would design its distribution system so that the problem would not occur.

Edmonton Power's proposal recognizes the immediate requirement for load support in the Castle Downs area and, unlike the intervener's proposal, takes into account existing distribution facilities, including existing substations, the areas they serve, and their present loading. On the other hand, Homestead appears to have essentially treated the north Edmonton area in isolation from the existing system. The electric load in north Edmonton is likely to follow a growth pattern established by the pattern of development of the area. As discussed in Section 3.2.3 of this report, there is considerable uncertainty as to how and when the area will be developed. This means that a similar uncertainty in the electric load growth pattern exists. The Board is of the view that existing facilities and the loads they serve must be a consideration in determining how best to serve near or adjacent developing loads. It therefore has difficulty accepting that a large area such as north Edmonton can simply be divided into approximately equal parts and a substation centrally located within those parts as Homestead appears to have done. If the electric distribution system in the north Edmonton area were an entity quite separate from the rest of Edmonton's distribution system, the approach used by Homestead might have merit.

The Board is unable to determine whether electric load growth might occur sooner in northeast Edmonton than northwest. However, it believes that Edmonton Power's single substation, centrally located, would provide greater flexibility to respond to whichever area develops first.

The Board carefully considered the intervener's arguments about "quality-of-life costs". It agrees that such intangible costs must be considered and reduced and has commented elsewhere in this report on some of the specific issues raised.

The Board concludes that Edmonton Power's single-substation proposal is preferable to the two-substation proposal suggested by Homestead.

4 PUBLIC SAFETY

4.1 Views of the Applicant

Edmonton Power stated that the substation would not introduce safety hazards to the area. Basins would be constructed underneath the transformers to contain any oil spills. In addition, the transformers would be completely enclosed in sound-absorbing, sealed-concrete enclosures. The applicant further stated that the entire substation would be encompassed by an 8 foot high security fence and that a 6 foot high cedar fence would be built outside the security fence. All fences would be locked and appropriately marked. Edmonton Power said it is not aware of any incidents where a member of the public had been exposed to a safety hazard in the vicinity of a substation.

4.2 Views of the Intervener

Homestead argued that substations of the size proposed should not be located in residential areas, noting that people have perceptions of hazards associated with such installations. It cited a recent incident that occurred at Edmonton Power's Petrolia substation as an example of accidents that might occur.

4.3 Views of the Board

The Board recognizes that safety hazards do exist around substations. Also, it is aware that the public is concerned about dangers from equipment failures.

The Board is convinced, however, that substations are and can be designed to reduce hazards to acceptable levels. For the proposed substation, the transformers would be enclosed to contain oil spills and fires. As well, adequate fencing and markings would be provided to prevent unauthorized individuals from entering the substation. Activities near the proposed substation, such as kite flying, could be subject to a greater hazard from the existing 240-kV line than from the substation. Therefore, the Board is satisfied that a substation, such as the one proposed, can be safely located within a residential area.

5 LOCATION OF THE SUBSTATION

5.1 Views of the Applicant

Edmonton Power proposed to locate the substation in the northwest quarter of section 33, township 53, range 24, west of the 4th meridian (see Figure 2). The substation would abut 97th Street, would be located partially on TransAlta's right of way, and would extend south onto what is now Homestead's property. Apart from TransAlta's 240- and 138-kV transmission lines, the area is an open field.

Edmonton Power stated that the proposed location was chosen because it is near the expected load centre, and 97th Street and TransAlta's right of way would provide a buffer on two sides. Additionally, the site would take advantage of existing distribution facilities and can be reached from 97th Street.

The applicant stated that the substation would be separated from the existing residences west of 97th Street by some 300 feet. Future residences would be separated from the substation by varying distances in excess of 100 feet. A 6 foot high berm would be constructed around the substation and a 6 foot high cedar fence on top of the berm. Trees and shrubs would be planted to provide screening. The noise level at the substation security fence would be below 50 dB(A), the City's long-term night-time noise limit. The separation distance, along with the berming, cedar fence, and screening, would make the substation inaudible to residents.

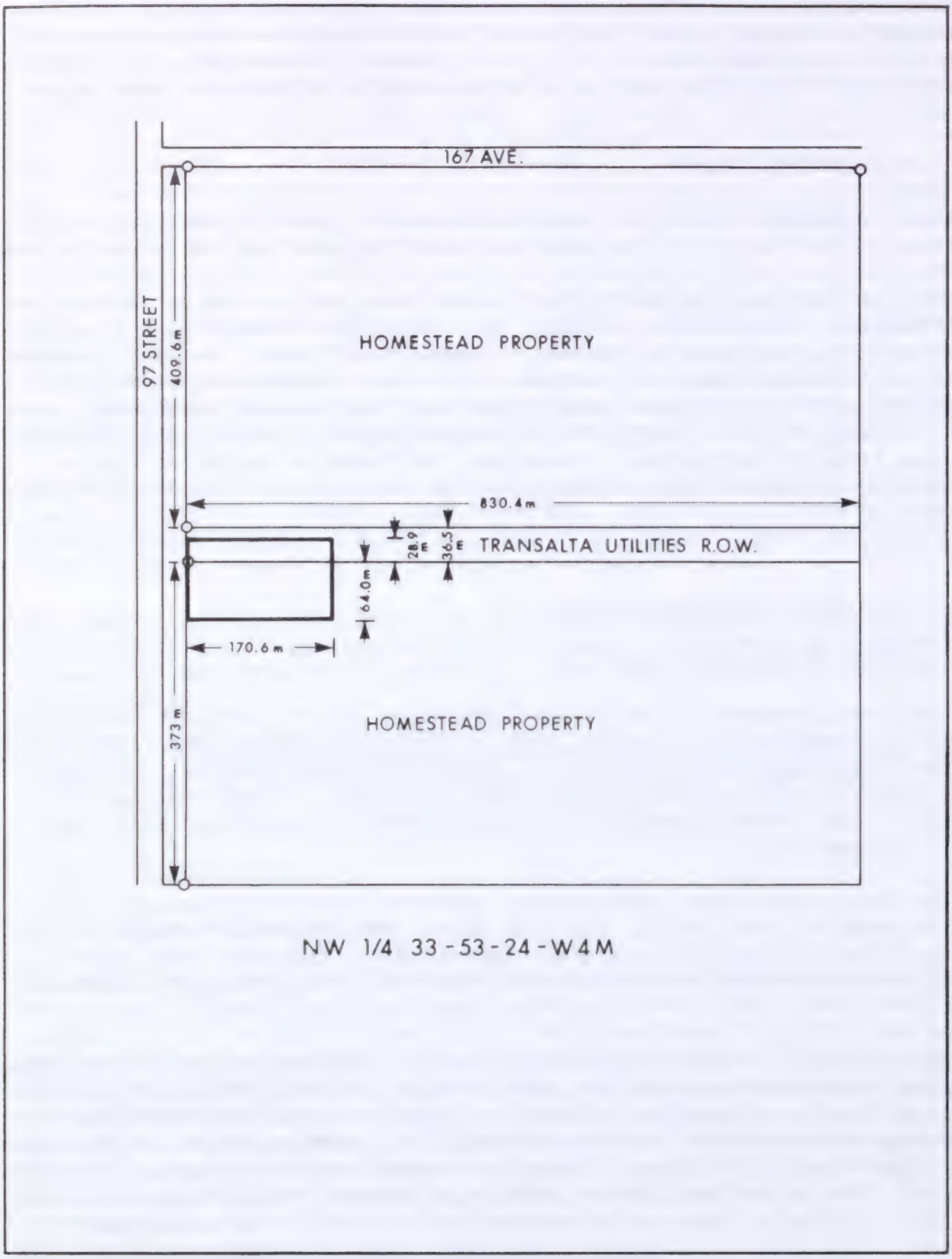

FIGURE 2 PROPOSED CASTLE DOWNS SUBSTATION LOCATION

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

In response to comments and testimony by Homestead, Edmonton Power stated that the area it defined for the proposed substation is sufficiently large to allow construction of a berm and planting of trees around the substation. The screening provided by the berm and the trees and the expected separation distances between the substation and future residences would mitigate any visual impact on adjacent residential development.

Responding to Homestead's contention that the substation would present a problem in designing and providing a drainage system for the area north of the substation, Edmonton Power stated that in its view the subject area could be drained via the ditch along 97th Street. It did not view this as a significant problem and, in any event, it would be the same regardless of whether the substation or some other development were constructed on the proposed site.

Edmonton Power indicated that it had considered locating the substation on City-owned land east of the proposed site. This easterly site, in a residential area called Belle Rive for which City Council had approved an Area Structure Plan, was rejected because of sewer and water lines to be located there and because an access road to the site would have had to be constructed far in advance of any other development occurring there. Early construction of the road would require spending of money sooner than would otherwise be necessary.

5.2 Views of the Interveners

Homestead stated that the substation, as proposed by Edmonton Power, would not be compatible with the residential development planned for the area. It stated that the introduction of the substation into the area would have a major effect on the ability to plan the area properly, resulting in a final plan that would meet only minimum standards for a residential area. Homestead contended that the land proposed for the site by Edmonton Power was too small to allow for proper berming and screening. The various high structures associated with the substation would be visually unacceptable to future residents in the area and the substation would emit a continuous noise of at least 40 dB(A). In response to a suggestion that background noise from traffic along 97th Street already existed, Homestead contended that the traffic noise is intermittent and therefore not as significant as the substation noise would be. It stated that noise created by traffic accessing the substation would also be significant. Homestead argued that the suggested distances separating the residences from the substation would not reduce these impacts.

Homestead stated that it had had a drainage study prepared for the area. It argued that introduction of the substation, along with the berm around it, would make it very difficult to drain the area north of the substation site. Because the area is very flat, inadequate slopes would be available to drain this area around the substation to a lake to be located south of the substation.

Homestead, while opposed to locating a substation in a residential area, questioned Edmonton Power why a site on City-owned land in the residential area of Belle Rive had not been chosen. It disagreed that lack of an access road was a constraint, stating that it could be provided since one would eventually be required.

5.3 Views of the Board

The Board has compared the substation location in Castle Downs and the one suggested by Homestead in Belle Rive on the basis of the evidence available. Residential development is proposed for both areas but the Board notes that an Area Structure Plan exists for the Belle Rive area whereas none has been approved for Castle Downs. Therefore, planning of the Castle Downs area can still accommodate the substation. The Castle Downs location is readily accessible and would not require prebuilding of an access road as would the Belle Rive location. Distribution facilities already exist along 97th Street in the Castle Downs area. Both areas are proposed for residential development, but the Castle Downs site would be buffered on two sides, 97th Street to the west and, to a degree, TransAlta's right of way to the north. The Board concludes that the Belle Rive location does not provide any compelling reasons to suggest it is preferable to the Castle Downs location.

The general argument was raised that major substations are essentially industrial developments and should not be located in residential areas. However, many large substations are already located in residential areas because such areas have a large electrical load requiring a nearby source. Even though justified by the load they serve, such substations, and particularly the larger ones supplied from high-voltage lines, should be designed, screened, and landscaped to suit the residential area they serve and certainly must not present a bare, industrial image.

The Board has considered the specific arguments put forward against locating the proposed substation in or near an urban residential area. It has considered these arguments in light of uncertainties associated with planning electric service to an urban area in which development has not been completely defined, and in light of various kinds of development that presently co-exist.

The Board is satisfied that the proposed substation would not impose any severe impacts on residents presently located west of 97th Street. It believes that 97th Street and the traffic associated with it, the separation distance, and the proposed berming, landscaping, and trees will sufficiently screen the substation.

In the absence of a specific plan for residential development near and including the substation site, the Board is unable to evaluate the specific impacts and concerns argued by Homestead. Nonetheless, it believes that remedial measures proposed by the applicant are essential and should substantially mitigate those concerns. Furthermore, it would appear to the Board that in this case the status of planning for the development of the area is such as to allow the substation to be properly accommodated. The Board does not accept that optimum planning of a totally new area necessitates

disallowing or preventing those developments that present problems and require extra planning effort, particularly if those developments provide a necessary service to the area.

The Board notes the existence of two transmission lines in the area and believes the addition of the proposed substation, located virtually beneath the 240-kV transmission line, would not add significantly to the visual impact already present, provided adequate screening is developed by the applicant.

The Board accepts the applicant's undertaking to limit the noise levels at the security fence to less than the maximum night-time level prescribed in the City's noise by-law. Since this level would be maintained inside the landscaped buffer screen, and some distance from any dwellings, noise should not be a problem.

The drainage situation was discussed in some detail but essentially involved moving storm water from north of the site to a storage lake south of it. This is not an insurmountable engineering problem and can apparently be handled on the 97th Street side of the site.

The Board notes Homestead's view that the area proposed by Edmonton Power is too small to allow proper screening and separation from adjacent residences. It also notes Edmonton Power's commitment to proper screening as specified by the City's Planning Department. The Board believes that the actual substation as designed for construction, any adjacent residential development, and the screening and landscaping should all be considered as a whole by all the planners involved to ensure that compatibility is achieved.

The Board concludes that the proposed substation site is appropriate and can be made acceptable.

6 DESIGN OF THE PROPOSED SUBSTATION

6.1 Substation Equipment

Edmonton Power proposed a conventional outdoor installation for the substation. Homestead suggested that the substation should be constructed as a sulphur hexafloride gas-insulated (SF6) installation. The Board believes that the following brief description of the two types of installation would be helpful.

Conventional Design

In a conventional 240-kV substation, aerial connection lines drop from the transmission lines to the 240-kV network in an outdoor switchyard. Live 240-kV conductors in the switchyard are exposed to and thus insulated by air only. Sufficient separation is provided between different conductors to avoid flashover. Individual structures are constructed to support each piece of equipment in the switchyard. Such a layout simplifies substation design and construction but requires a relatively large area.

SF6 Design

In an SF6 substation, aerial lines connecting the substation to the transmission lines are still required. The 240-kV network of the substation, with the exception of transformers, is fully insulated by pressurized sulphur hexafloride gas in totally enclosed metalclad chambers. Since pressurized sulphur hexafloride gas has a much higher dielectric strength (insulating capability) than atmospheric air, space requirements for separation of equipment are less. An SF6 substation is thus more compact than an equivalent conventional air-insulated substation. SF6-insulated components are normally housed in a building but the transformers remain outdoors.

6.1.1 Views of the Applicant

In response to Homestead's suggestion that the substation be designed as an SF6 installation, Edmonton Power stated that enclosed substations are best suited to locations such as downtown areas of cities where land costs are very high. Edmonton Power determined that the land required for the actual Castle Downs substation would be reduced by only some 50 per cent for an SF6 design and that it would not permit full advantage to be taken of TranAlta's right of way. The total area, including that required for berming and screening, would therefore only be reduced by approximately 3 acres.

Edmonton Power estimated that the approximate cost of conventional switchgear would be $1.5 million, and of equivalent SF6 switchgear, $2.8 million. Also, a further $350 000 would have to be added for a building to contain the SF6 equipment. An SF6 installation would therefore cost some $1.65 million more than a conventional one. Edmonton Power estimated that a building for the SF6 equipment would be approximately 80 feet long, 50 feet wide, and 33 feet high.

6.1.2 Views of the Intervener

Homestead stated that, if the Board determined that the substation should be located in Castle Downs, it should require Edmonton Power to design and construct the substation as an SF6 installation. It suggested that the total land required for an SF6 installation would be approximately 1.5 acres.

Homestead argued that SF6 switchgear would cost only some 20 to 25 per cent, or $500 000, more than the $1.5 million to $2.0 million it estimated for conventional switchgear. It argued that a further advantage of SF6 switchgear was easier maintenance, particularly in winter, because the switchgear would be housed in a building.

Homestead stated that a conventional installation, with its associated larger land requirement, would cost the City extra money in lost tax revenues, saying this could amount to half a million dollars over 30 years. In addition, because more land would be required for a conventional installation, the cost of land would be higher. Homestead contended that these additional cost considerations would make the SF6 alternative almost equal in cost to the conventional substation.

Finally, the interveners argued that the social and environmental costs associated with a conventional installation would be virtually eliminated with an SF6 installation because much of the equipment would be enclosed in a building.

6.1.3 Views of the Board

The Board has considered the arguments for an SF6 installation as opposed to the conventional design proposed by the applicant. It agrees that any SF6 portion of a substation would be smaller and lower, hence less noticeable within the overall substation.

In evaluating the costs associated with either design, the Board assumed that an SF6 installation would cost some $900 000 more than a conventional design (an average of the differing cost estimates given by the applicant and intervener) and require a building at a cost of some $350 000. It assumed an SF6 installation would require some 50 percent less land or 3 acres as opposed to the approximately 6 proposed by the applicant. It assigned an average land cost of $100 000 per acre, resulting in the larger land requirement costing some $300 000 more. The Board has made no allowance for revenue tax losses, assuming these losses would be offset by not having to service the area. On the basis of these assumptions and cost estimates, the Board believes an SF6 installation would cost some one million dollars more than a conventional installation. The Board has considered Homestead's arguments regarding maintainability of SF6 equipment but does not accept this as a major argument in favour of SF6 equipment.

The Board has interpreted Homestead's desire for an SF6 installation as based on an argument that the social and environmental impacts would be less than for a conventional design. In this regard, the Board notes that the existing transmission lines would not be changed, and that the structures required to connect the 240-kV line to the substation would still be required with an SF6 installation. Additionally, the Board notes that a substantial building would be required for SF6 equipment. The Board accepts that the required land area would be reduced but is doubtful that either type of installation would materially add or detract from the social and environmental impact of existing facilities and therefore does not agree that the additional cost for an SF6 installation is justified. As stated earlier in this report, the Board believes that mitigative measures proposed by the applicant will ameliorate the effective presence of the substation in the community and that consideration of the substation in the design of the neighbourhood would achieve compatibility.

6.2 Substation Circuit Configuration

6.2.1 Views of the Applicant

Edmonton Power selected a 240-kV ring bus consisting of four circuit breakers. TransAlta's 240-kV transmission line CP 920L, would be split and connected to the substation effectively as two infeeds across a breaker of the ring bus. The remaining two bus sections of the ring bus would be for transformer connections. The configuration of the proposed substation is shown on Figure 3.

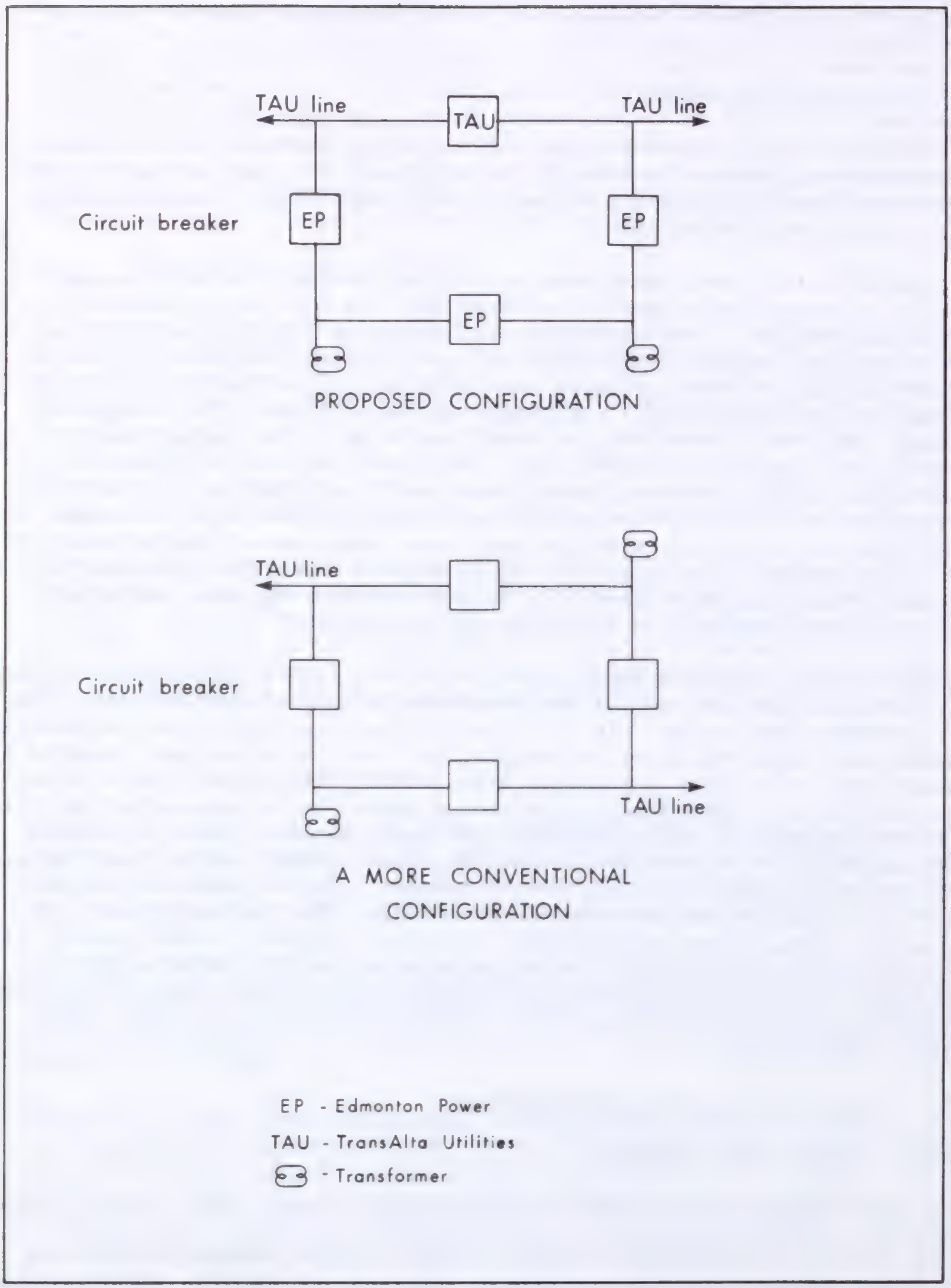

FIGURE 3 CIRCUIT BREAKER CONFIGURATION

The applicant stated that it compared the reliability of the proposed design with that of conventional design which alternated transformer and line elements, also shown on Figure 3. Edmonton Power acknowledged that the latter arrangement is more reliable but submitted that the proposed arrangement would meet TransAlta's requirement for operational control of the breaker interconnecting TransAlta's 240-kV transmission line. Therefore, it decided to accept a less-reliable circuit configuration in order to comply with TransAlta's requirement. Edmonton Power stated that its proposed layout was still acceptable.

6.2.2 Views of the Board

In the Board's view, additions to Alberta's interconnected system must be designed and constructed in a manner that ensures reliability of service. The Board recognizes that a number of parameters must be considered, and judgements made, to determine the level of reliability that should be provided in specific instances. In an urban area particularly, a significant system outage or failure can have serious public health and safety consequences.

On the other hand, cost implications must be considered. In this instance the Board notes that, in order to allow TransAlta to control its 240-kV line, Edmonton Power has selected a configuration that results in some loss of reliability of the substation. In particular, the failure of the breaker between the two 240-kV lines, or between the transformers, or a false operation of either of those breakers, could stop all distribution power supply from the substation. The length of the disruption would depend on how long it would take Edmonton Power to determine the nature of the problem, isolate the problem equipment or area, and re-energize the substation. In other words, the substation would not continue to supply electricity under several of the single-contingency outage situations that might occur in the substation.

The Board recognizes that the circuit configuration, and attendant reliability, proposed by Edmonton Power exists in other substations in the system. It is concerned, however, that the same philosophy is apparently being applied regardless of the size of the substation or the area it serves. In this case, the substation will eventually serve a load of some 170-MVA in an area that could have some 200 000 inhabitants. Yet the substation would not be able to provide continuous service during a single-contingency outage, even if that outage were caused by something as innocent as a faulty relay operation or personnel error. The Board finds it somewhat surprising that TransAlta's need to control its 240-kV line is seen to have priority over the reliability of the substation. It points out, however, that TransAlta was not a party to the hearing and its views could therefore not be obtained.

The Board recognizes that the load served by the proposed substation would initially be much less than its 170-MVA capacity. It therefore accepts the proposed physical layout of the substation for the first four years of operation. However, the Board would expect Edmonton Power to file appropriate applications for approval to alter the substation in order that continuous service from the substation would be provided during single-contingency outage situations beyond the fourth year. The Board would further expect Edmonton Power to make provision in its present design to allow such future alteration to take place without disruption of service to the customers being served by the substation.

7 FINDINGS

The Board finds that:

- Additional substation capacity is required to provide electricity to the north Edmonton area.

- The applicant's proposed substation is preferable to the two-substation concept proposed by the intervener.

- A distribution substation can be safely located within an urban residential area provided measures are taken to minimize the safety hazards.

- The location proposed by the applicant in the Castle Downs area of north Edmonton is acceptable and the substation can be accommodated in an integrated development plan for the area.

- Conventional air-insulated equipment is acceptable. Given the location of the substation, surroundings, and the mitigative measures proposed, the higher cost of an SF6 installation is not justified.

- The substation circuit configuration proposed by the applicant is acceptable for the initial operation, after which the configuration should be altered to ensure continuous service during single-contingency outage situations in the substation. Provision to allow such future alteration without disruption of service must be provided in the initial design of the substation.

8 DECISION

The Board has publicly heard Application 810899, by The City of Edmonton under Sections 12, 14 and 17 of the Hydro and Electric Energy Act, for a permit to construct and a licence to operate a 240/14.4-kV substation in the Castle Downs area of The City of Edmonton, and for an order allowing the interconnection of the substation to TransAlta Utilities Corporation's transmission system. Having studied the evidence presented at the public hearing, held in Edmonton on 24 and 25 June 1982, the Board is prepared to grant the application in the manner and for the reasons set out in this report. The Board intends to condition the permit for the substation to require that:

- Beyond the initial four years of operation, the substation will be capable of providing continuous service to customers during single-contingency outage situations in the substation.

- Prior to the start of construction of the substation, Edmonton Power shall satisfy the Board that provision has been made to allow future modification of the substation configuration without disruption of service to the customers being served by the substation.

Subject to the approval of the Ministers of Environment and Energy and Natural Resources, insofar as the application affects matters of the environment, the

Board will issue the appropriate permit and licence and interconnection order in due course.

DATED at Calgary, Alberta, on 1 October 1982.

ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman

C. J. Goodman
Board Member

R. G. Evans

R. G. Evans
Acting Board Member

T. F. Homeniuk

T. F. Homeniuk
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary, Alberta

DOME PETROLEUM LIMITED — Decision 82-32
EXPANSION OF EMPRESS GAS REPROCESSING FACILITIES — Application 810998

1 INTRODUCTION

1.1 The Application

Dome Petroleum Limited applied, pursuant to section 26 of the Oil and Gas Conservation Act,* for approval to reprocess natural gas and thereby recover a mixture of ethane, propane and heavier hydrocarbons at a proposed expansion of its Empress straddle plant in the SW 1/4 of section 12, township 20, range 1, west of the 4th meridian. The existing facility is designed to reprocess a maximum of 41.5 x 10^6 cubic metres per day (m^3/d) of sweet gas, from which 2842 m^3/d of ethane and 2407 m^3/d of propane plus can be removed. The proposed expansion would increase capacity by 55.4 x 10^6 m^3/d, from which an additional 5448 m^3/d of ethane and 2773 m^3/d of propane plus would be removed. No sulphur or sulphur compounds would be emitted to the atmosphere.

1.2 The Interventions

The application was supported by several interveners who maintained that straddle plants offer the most economic, orderly, and efficient means for extracting ethane from natural gas streams. However, while not actually opposing the project, some interveners believed that the proposed plant may be oversized, and that it could therefore prejudice applications for field ethane extraction facilities. Also expressed were concerns that approval of the proposed expansion might limit the proprietary rights of gas producers to extract ethane from their gas streams.

1.3 The Hearing

A public hearing of the application was held in Calgary on 13, 14 and 15 April 1982, with N. Berkowitz, P.Eng., C. J. Goodman, P.Eng., and G. A. Warne, P.Eng., sitting.

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* Formerly section 38 of The Oil and Gas Conservation Act.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Dome Petroleum Limited (Dome) F. M. Saville W. M. Smith	Dr. A. H. Younger, P.Eng. J. Caffery, P.Eng. D. C. English, P.Eng. R. S. Johnson all of Dome Petroleum Limited C. D. Annable, P.Eng. of Fish International Canada Ltd. R. J. Cradock, P.Eng. of Pan-Alberta Gas Ltd. R. T. Liddle, P.Eng. of TransCanada PipeLines Limited
Alberta Energy Company Ltd., Esso Resources Canada Ltd., and Hudson's Bay Oil and Gas Company Limited (AEC/Esso/HBOG) D. G. Davies	
The Alberta Gas Ethylene Company Ltd. (AGEC) F. R. Foran	
Alberta Natural Gas Company Limited (ANG) J. R. Smith, Q.C.	
Amoco Canada Petroleum Company Ltd. (Amoco) F. B. Matthews	
Atcor Resources Limited (Atcor) N. Stapon	J. Pletcher, P.Eng.
Canadian Hunter Exploration Ltd. (Cdn. Hunter) B. K. O'Ferrall	D. L. Bowman, P.Eng.
Chevron Standard Limited (Chevron) L. M. Sali	

THOSE WHO APPEARED AT THE HEARING cont'd

Principals and Representatives (Abbreviations used in Report)	Witnesses
Esso Resources Canada Ltd. (Esso) D. G. Hart, Q.C.	Dr. P. Grant, P.Eng. J. Park, P.Eng.
Gulf Canada Resources Inc. (Gulf) H. B. Holmberg	
Northwestern Utilities Limited (NUL) C. K. Sheard	N. Doherty, P.Eng. L. Graburn, P.Eng.
PanCanadian Petroleum Limited (PanCanadian) W. J. Hope-Ross	
Petro-Canada Exploration Inc. (Petro-Canada) J. W. Gallagher	
ProGas Limited (ProGas) J. J. Marshall	
Sulpetro Limited (Sulpetro) R. Beattie	
TransCanada PipeLines Limited (TCPL) M. Brown	
Energy Resources Conservation Board staff C.J.C. Page W. J. Schnitzler, P.Eng. M. T. McCormick	

2 ISSUES

In considering the subject application, the Board believes the principal issue to be the need for the proposed plant, a matter that depends upon the annual gas volumes expected to flow by Empress over the next 15-20 years and on the ethane content of the gas.

Other issues raised by the application are:

- the volumes and costs of recovered ethane,
- marketing and impact on the Alberta petrochemical industry,
- resource conservation and the degree of upgrading in Alberta,
- the environmental impact of the proposed plant, and
- the impact of straddle plant expansion on proprietary rights of gas producers.

3 NEED FOR THE PROPOSED EXPANSION OF REPROCESSING CAPACITY

3.1 Views of the Applicant

Dome stated that the proposed expansion is warranted by the new gas markets which TCPL is developing, and that its gas market forecast, far from being overly optimistic, is conservative. It noted that 40 per cent of the applied-for capacity is required to process Pan-Alberta volumes which are approved and committed, and stated that the NEB is likely to approve a substantial portion of export volumes it is now considering. Dome also thought it reasonable to expect that incentives offered by the Alberta and federal governments will promote continued growth of the domestic market.

3.2 Views of the Interveners

Esso believed Dome's feedstock supply estimate to be, at best, tentative, since it assumed growth of eastern Canadian demand and new exports. In Esso's view, both these markets hold less growth potential than forecast by Dome, and a smaller facility should therefore be considered in order to avoid creating costly under-utilized capacity. Chevron and Cdn. Hunter also doubted that all of the additional capacity would be required.

TCPL supported the application and Dome's forecast of the gas volumes going through Empress, and believed that growth in gas markets would actually be greater than Dome projected. AGEC also accepted Dome's market forecasts as entirely reasonable.

Petro-Canada expressed concern that future gas-processing proposals, coming before the Board with firm gas supply arrangements, might be hampered if the proposed facility were not operating at capacity.

3.3 Views of the Board

Based on its view of the probable gas markets over the next 15 to 20 years, the Board believes that there is little risk of gas volumes at Empress being so low or so lean as to substantially increase the cost of service for ethane supply to Alberta users. The Board accepts that future upstream deep-cut units may reduce ethane volumes available to the proposed plant, but does not believe that such potential reductions would be great enough to warrant reducing its size.

The Board also notes that the proposed plant would recover 73 per cent of the ethane in the gas stream, as compared with 44 per cent achieved in the existing facility, and therefore sees economic incentives for using the new plant as a base-load facility.

4 ETHANE CONTENT OF GAS AT EMPRESS

4.1 Views of the Applicant

The application included a material balance for a "lean ethane" case which assumed a 3.83 per cent ethane content in the inlet stream. At the hearing Dome also noted that ethane concentrations had, over the previous 6-month period, increased to approximately 4.2 per cent, and referred to this as the "rich ethane" case. Dome therefore concluded that if its proposed plant were "upstreamed" by field ethane extraction facilities which processed 28.2×10^6 m^3/d (1.0 Bcf/d) with 7 per cent ethane, the ethane content of the total gas stream passing Empress would only be lowered by some 8 per cent, and that a plant design based on the "lean" case could easily accommodate any foreseeable upstreaming. However, in a post-hearing letter to the Board and the hearing participants, Dome revised its assessment noting that an 8 per cent drop in ethane concentration was contingent on upstreaming no more than 8.45×10^6 m^3/d (300 MMcf/d) of gas with a 7 per cent ethane content.

4.2 Views of the Interveners

None of the interveners commented on the present or future ethane content of inlet gas at Empress.

4.3 Views of the Board

The Board agrees that a 4.2 per cent ethane content represents a reasonable "rich ethane" case for inlet gas at Empress, especially if the average ethane contents of gas streams expected to enter the NOVA gathering system are taken into account, but believes that Dome's "lean" case, predicated on upstreaming of 8.45 x 10^6 m^3/d (300 MMcf/d), may not make adequate allowance for future upstream processing of gas entering Empress.

However, the Board recognizes the uncertainties which inevitably surround future upstreaming, and, with respect to the possibility of such upstreaming seriously affecting the economic viability of the proposed plant, reiterates its view, expressed in Decision 76-2, that this represents a business risk which the applicant must accept.

5 ETHANE RECOVERY VOLUMES

5.1 Views of the Applicant

Dome stated that the recovery efficiency of the proposed plant would be approximately 73 per cent and, assuming the lean ethane case, that this efficiency would result in daily production of some 5625 m^3 (35 600 bbl) of ethane. It also contended that a straddle plant would permit the reprocessing of all gas leaving the province, and was therefore in the public interest.

5.2 Views of the Interveners

All interveners agreed that the proposed facility would recover some ethane not recovered elsewhere. However, Cdn. Hunter argued that the ethane volumes attributed to the plant should be adjusted to allow for volumes that would be recovered in field processing plants recently proposed. Cdn. Hunter, as well as Chevron and Esso, also suggested that most of the ethane which Dome proposes to extract at its expanded straddle plant could be competitively recovered in field processing facilities. Such facilities could, additionally, strip ethane from gas supplies for the Alberta domestic market. All existing and proposed ethane recovery facilities, including field facilities proposed by several interveners, should therefore be taken into account when evaluating Dome's proposal.

5.3 Views of the Board

Assuming a 4.2 per cent ethane content and 73 per cent recovery, the Board estimates that, in the absence of upstreaming, Dome's proposed plant would recover some 6035 m^3/d (38 200 bbl/d) of ethane. If upstreaming reduced the average ethane content to 3.55 per cent, the plant would recover approximately 5100 m^3/d (32 280 bbl/d). The Board believes that these two estimates indicate the range of ethane volumes and daily ethane production likely in the proposed facility.

6 COST OF ETHANE

6.1 Views of the Applicant

Dome estimated the capital cost of the proposed expansion, exclusive of inventory costs and interest during construction at some 168 million (1982) dollars. Based on the present cost of service formula, the cost of ethane from the facility would therefore be higher than the current average of \$68.00/m^3 (\$10.75/bbl). Dome submitted, however, that if operated at capacity, the proposed plant would increase this average price by only 0.5 per cent. Plant operation at half capacity would make the increase 2 per cent. More specifically, Dome quoted ethane costs of \$101.20/m^3 (\$15.99/bbl) in 1986 when the plant would not be fully loaded, and \$90.00/m^3 (\$14.22/bbl) in subsequent years, when it was expected to operate at capacity, but pointed out that a one-year delay of its construction schedule would increase the total capital cost of the project by 10 per cent.

6.2 Views of the Interveners

Esso and Chevron questioned the contention that straddle plants provide the most economic means of recovering incremental volumes of ethane, and Esso presented a comparison of ethane costs for straddle and field plants in support of its view that until 1987, field plants would be more economical than the proposed plant. Esso also presented field plant costs for gas passing Empress based on TCPL's low market forecast. These figures suggested that field plants would enjoy increasing economic advantages over the straddle plant.

6.3 Views of the Board

The Board accepts the applicant's view that the cost of ethane from the proposed plant would modestly exceed the present average Alberta price, and concludes that approval of the applicant's proposal would have a minimal impact on provincial ethane prices.

7 MARKETING AND IMPACT ON THE ALBERTA PETROCHEMICAL INDUSTRY

7.1 Views of the Applicant

Dome contended that, in the short term, its proposal would provide an additional supply of ethane for the export market and that export of surplus ethane has benefited Alberta's petrochemical industry. It also stated that an expanded facility would meet part of the requirements for AGEC's second ethylene plant (AGE II), which is scheduled to come on stream in 1984, and could reasonably supply ethane for a future AGE III.

7.2 Views of the Interveners

Esso argued that gas exports to the United States may not be as high as Dome expects, and that insufficient feedstock for the expanded straddle plant could adversely affect the petrochemical industry by raising the cost of ethane. Esso and other interveners also suggested that under-utilization of the proposed additional capacity would enable Dome to argue against future proposed field plants.

Chevron believed that export of significant quantities of ethane would not necessarily be in the public interest of Alberta, but AGEC, which has already undertaken to purchase all ethane recovered at the proposed facility, maintained that straddle plants are the most cost-effective and efficient means of providing feedstock for Alberta's petrochemical industry.

7.3 Views of the Board

In the Board's view, the public interest dictates secure long-term sources of ethane for Alberta's petrochemical industry, and inevitably from time to time exportable surpluses of ethane will be available. Any negative impact of such exports must therefore be weighed against benefits accruing to Alberta markets. The Board further notes that the Gas Resources Preservation Act requires that any such proposed exports be dealt with in an application to the Board and that a permit be issued prior to removal of ethane from the province.

The Board concurs with the cost of service data submitted by the applicant, and takes the position that overall ethane cost increases of 0.5 to 2.0 per cent, which could result from approval of the proposed plant, are relatively insignificant and quite acceptable.

8 DEGREE OF UPGRADING

8.1 Views of the Applicant

Dome stated that its proposed facility would provide an additional supply of ethane, and assist the development of the Alberta petrochemical industry. Ethane production over the 1984-1986 period is contracted to AGE II, and the remainder would be available for export until required for AGE III.

8.2 Views of the Interveners

Esso contended that the proposed facility is geared toward satisfying the export market rather than the requirements of Alberta's petrochemical industry, and several other interveners believed that ethane export would adversely affect petrochemical activity in Alberta.

8.3 Views of the Board

The Board accepts that Dome has an agreement in principle with AGEC to supply AGE III from 1986 on, and understands that an application will probably be filed later to allow export of any ethane surplus to Alberta's requirements between 1984 and 1986.

Having regard for the fact that export is expected to be of relatively short duration and that the bulk of ethane recovered at the proposed facility would be further upgraded in Alberta, the Board believes that ethane recovery in the proposed plant would be in the interest of the province.

9 CONSERVATION AND ENVIRONMENTAL IMPACT

Dome stated that the plant would be designed to be highly energy-efficient, to have minimal impact on the environment and to comply with all relevant regulations.

None of the interveners seriously questioned the conservation and environmental aspects of the proposed facility.

The Board notes that all concerns of Alberta Environment were satisfied before the hearing, and that the proposed facility would incorporate the latest commercially proven technology.

10 PROPRIETARY RIGHTS OF GAS PRODUCERS

Dome maintained that the lower costs associated with ethane recovery in straddle plants, and the volumes of gas which such facilities process, make the proposed expansion in the public interest.

However, Cdn. Hunter took the position that potential perils to Alberta gas producers could be reduced by recognizing the rights of all producers to further upgrade their resources, provided they could do so competitively. It stressed that the producers have spent risk capital to find oil and gas, and that they should not be discouraged from maintaining ownership of their gas and co-products. Any moves that tended to discourage them in this matter would not be in the public interest of Alberta.

As noted in its previous decisions, the Board believes that subject to other overriding aspects of the public interest, a producer should have the opportunity to recover and upgrade ethane contained in its oil and gas. With this in mind, the Board does not accept that approval of the subject application would necessarily preclude subsequent approval of future proposals to recover ethane in field locations upstream of Dome's plant.

11 FINDINGS

From the evidence before it, the Board finds as follows:

- the volumes of gas expected to flow by Empress are sufficiently large, and contain a sufficiently high concentration of ethane, to warrant recovery of the ethane,

- the costs of ethane to be recovered in the proposed facilities will be only marginally greater than the present average cost of ethane in Alberta, and are not likely to have a significant adverse effect on the Alberta petrochemical industry,

- the proposed facilities would permit the efficient extraction of ethane and enhance secure long-term supplies in the province,

- the proposed facilities are not expected to have a significant adverse environmental impact, and

- existing and developing markets for ethane in Alberta, and short-term export markets, make the proposed facilities economically viable. Potential future upstream field extraction operations could affect the economics of the project, but this is a business risk which the applicant must address.

12 DECISION

The Board is prepared to approve the application, subject to receipt of the necessary Ministerial Approval.

DATED at Calgary, Alberta, on 19 October 1982.

ENERGY RESOURCES CONSERVATION BOARD

N. Berkowitz, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

G. A. Warne

G. A. Warne, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION FOR COMPULSORY POOLING — Decision 82-33
NORRIS FIELD — Application 820258

The Board has reviewed the report of its examiners, attached hereto, respecting Application 820258 for an order that all tracts within Section 19, Township 53, Range 17, West of the 4th Meridian, be operated as a unit for the production of gas from the Viking Formation through the well, VOYAGER ET AL NORRIS 14-19-53-17.

For purposes of its decision, the Board adopts the examiners' recommendations. However, the Board thought it appropriate to comment on the costs for which tract owners may be liable to the operator by way of a compulsory pooling order, pursuant to the Oil and Gas Conservation Act (the Act).

Section 72(4)(d) of the Act provides:

> (4) An order made under subsection (3) shall provide for the following matters:
>
> > (d) for the payment of the actual cost of the drilling of the well whether drilled before or after the making of the order, and for the payment of the actual costs of the operation and abandonment of the well, but the share of the costs of drilling, operating and abandonment of the well and penalty, if any, as provided for by subsection (5) and payable by any owner who fails to pay his share by the time specified in the order, shall be recoverable only out of that owner's share of production from the drilling spacing units;

Section 74(5) of the Act provides:

> (5) The Board in its order may specify that in the event production of oil or gas is obtained and the owner of a tract fails to pay his share of the actual cost of drilling the well by the time specified in the order, then the amount payable by that owner shall include, in addition to his tract's share of the actual cost of drilling, a penalty payable to the operator not exceed 1/2 of his tract's share of the actual cost of drilling.

The Board notes that, pursuant to those sections, the tract owner may be liable to the operator for his share of three costs; being:

(1) The actual cost of drilling the well;

(2) The actual cost of operation of the well;

(3) The actual cost of abandonment of the well.

The Board further notes that, of the three costs, only the actual cost of drilling the well is subject to a penalty. Section 75(1) of the Act provides that the actual cost of drilling a well includes the cost of drilling the well to and completing it in the formation named in the compulsory pooling order.

Having regard to the express words of the legislation, the Board concludes that the penalty has been established by the Legislature in respect to the capital costs associated with the drilling of the well and it is clear that the penalty will not apply to costs which cannot properly be considered as part of the actual costs of the drilling of the well, whether they be of a capital nature or not.

The term "actual cost of drilling the well", by definition, does not include the costs of an associated pipeline. In some cases, it is clear that the construction of a pipeline is necessary and incidental to the operation of the well. Accordingly, the Board is of the opinion that where, as part of the operation of a well, a pipeline is constructed and operated, the costs must be included in the costs of operation of the well. Since the capital costs attributable to the pipeline are not included in the actual costs of the drilling of the well, and since those are the only costs to which a penalty may be applied, then no penalty may be applied to the capital costs of the pipeline. The costs related to the construction and operation of the pipeline must be reflected in the actual costs of operating the well and would be allocated to each tract on a cost of service basis.

DATED at Calgary, Alberta, this 30th day of September, 1982.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy
Vice Chairman

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY VOYAGER PETROLEUMS LIMITED
COMPULSORY POOLING
NORRIS FIELD

Examiners' Report E82-22
Application 820258

1 INTRODUCTION

1.1 The Application

Voyager Petroleums Limited (Voyager) applied pursuant to section 72 of the Oil and Gas Conservation Act (the Act) to have all tracts within section 19, township 53, range 17, west of the 4th meridian, operated as a unit for the production of gas from the Viking Formation through the well, VOYAGER ET AL NORRIS 14-19-53-17 (the well). Voyager proposed that the production and costs be allocated to each tract on an areal basis. Voyager was able to obtain agreements with the mineral rights owners of the south half and northwest quarter of section 19, however, it was not able to obtain a voluntary agreement with Mr. J. M. Lazarenko, who owns the mineral rights to the northeast quarter of section 19.

Mr. Lazarenko filed an intervention to the application.

1.2 The Hearing

A public hearing of the application was held on 4 August 1982, in Edmonton, Alberta, before Energy Resources Conservation Board-appointed examiners, G. A. Warne, P. Eng., J. R. Nichol, P.Eng., and D. Holgate.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Voyager Petroleums Limited (Voyager) E. Chillack, LL.B.	F. E. Starratt, P.Eng. D. A. Pearce J. W. McIntosh, P.Eng. E. Chillack, LL.B.
J. M. Lazarenko, Q.C.	J. M. Lazarenko, Q.C.
Energy Resources Conservation Board staff N. F. Lord	

2 THE ISSUES

The examiners believe the issues to be:

- the need for a pooling order pursuant to section 72 of the Act, and
- the terms of any order, issued, specifically respecting

  a non-participating penalty,

  the personal liability of the intervener with respect to costs related to the well, and

  the actual costs attributable to the well.

3 THE NEED FOR A POOLING ORDER

3.1 Views of the Applicant

Voyager submitted that repeated attempts to reach a voluntary pooling agreement with Mr. Lazarenko over the period of December 1980 to June 1982 had been unsuccessful. It referred to numerous exchanges of correspondence, telephone conversations, proposals, and counter proposals which occurred during the period. It added that it had a contract to market the gas and that the interest owners in the spacing unit, other than Mr. Lazarenko, have reached agreement for pooling their interests.

In October 1981, Voyager drilled the well and subsequently completed it as a Viking gas well. Voyager submitted that the well is tied-in and that it is fully capable of producing the spacing unit's share of pool production.

The applicant submitted that since no voluntary agreement had been reached after extensive negotiations, a pooling order based on area should be issued.

3.2 Views of the Intervener

Mr. Lazarenko agreed that extensive efforts had been made to reach agreement on voluntary pooling of interests within the spacing unit without success. He added that although the points of disagreement were not substantial, it was important that detailed provisions be set forth fixing the manner in which revenues would be shared and expenses allocated among the parties. Mr. Lazarenko did not object to a pooling order being issued or to costs and production being distributed among the tracts on the basis of area.

3.3 Views of the Examiners

The examiners believe that a reasonable attempt to reach a pooling agreement has been made, that a pooling order should be issued and that the order should provide for costs and production to be distributed on the basis of area.

4 TERMS OF THE ORDER

4.1 Views of the Applicant

Voyager requested that a penalty as allowed under the Act be prescribed as interest on any outstanding amount owed by Mr. Lazarenko respecting his tract's share of the costs of the well. Voyager further submitted that the rate of interest should be fixed and based on the prime interest rate plus 1 per cent at the Toronto Dominion Bank on the date of the hearing, that bank being the bank at which Voyager does its banking. The interest rate would be applied to the amount owed the applicant by Mr. Lazarenko effective 30 days after a statement of costs had been submitted to Mr. Lazarenko.

Voyager added that the well was inadvertently placed on production in April 1982. It further added that the well has produced roughly enough gas to generate the revenue required to cover its completing and equipping costs.

Voyager submitted it was not prepared to enter into a voluntary agreement with Mr. Lazarenko containing a clause limiting his personal liability with respect to the well's costs, partly since there would be future costs attributable to the well after production has ceased.

These future costs might result from well workover, abandonment, and lease restoration work.

Voyager further submitted that it was prepared to submit a statement of the well costs already incurred after a detailed accounting has been performed. It submitted an estimate of costs which it contended was very close to the actual total costs of drilling, completing and tying-in the well. Voyager indicated that it was prepared to provide these figures to Mr. Lazarenko, but that it preferred to wait until a detailed accounting of these costs has been completed. Voyager asked that fixed cost figures not be included in any pooling order.

Voyager stated that the costs incurred to the date of the hearing consisted of \$95 000 for drilling and evaluating the well, completion costs of about \$34 000 and \$67 000 for the flow line to the well, which together totalled about \$195 000.

4.2 Views of the Intervener

Mr. Lazarenko submitted that as he was being forced to participate in the project, he should not be subject to any penalty, however, he stated that if a penalty comprising interest on the amount outstanding is stipulated in an order, the rate of interest applied should be fixed at 14-1/2 per cent, corresponding to that set in a previous pooling order, which he contended was precedent-setting. He also submitted that the interest charge on the amount owed by the owner of a tract should not come into effect until 60 days after he has received a statement of the costs involved.

Mr. Lazarenko submitted he was not prepared to enter into a voluntary agreement with Voyager which did not contain a clause exempting him from any personal liability for costs attributable to the well. He also indicated he wished to have his tract's share of the well costs taken out of production.

Mr. Lazarenko further submitted that he was not prepared to enter into any agreement with Voyager until he received a statement of the exact costs which will be attributed to his tract. Mr. Lazarenko stated that he had requested such a statement from Voyager previously, but to the date of the hearing none had been supplied. Mr. Lazarenko contended that the drilling and completion costs for the well should be specified in the pooling order.

4.3 Views of the Examiners

When a compulsory pooling order is issued, a penalty may be assessed against an owner of a tract pursuant to section 72(5) of the Act when the owner fails to pay his tract's share of drilling costs by the time specified in the order. The penalty is to be related to the owner's share of the drilling and completing costs. Costs associated with tying-in the well to the production system are not taken into consideration when calculating the penalty. The examiners believe that if a pooling order is issued pursuant to the subject application it would be appropriate to prescribe such a penalty.

Section 72(5) provides for a maximum penalty of 50 per cent of the costs of drilling and completing the well. The examiners believe that it would normally be appropriate to apply this penalty as a fixed percentage of these costs. However, the applicant indicated it was in favour of the penalty being expressed as interest on the amount owing after the effective date specified in any order that might be issued. The examiners therefore agree the penalty should be determined on that basis in this case. The examiners further believe it is reasonable to apply a penalty corresponding to the prime interest rate plus 1 per cent, however, the examiners do not believe that it would be appropriate to specify the prime interest rate as of the date of the hearing.

The examiners feel that a penalty corresponding to the prime interest rate plus 1 per cent as of the date of issuance of the compulsory pooling order or the issuance of the statement of the drilling and completion costs, whichever is the later, should be applied. The maximum penalty could not exceed 50 per cent of the actual costs of drilling and completing the well.

The examiners believe that a reasonable time for interest to begin to accumulate is 30 days after the statement of costs has been presented to Mr. Lazarenko. The examiners note that there could not be a penalty if Mr. Lazarenko's share of the costs are paid within 30 days of the delivery to him of the statement of costs or the date of the order, whichever is the later. In addition, since the well has accumulated considerable production, sufficient proceeds from the sale of the gas attributable to Mr. Lazarenko's tract appear to have been accumulated to cover most of Mr. Lazarenko's share of the costs and little, if any, penalty is likely to result.

The examiners believe that the liability of Mr. Lazarenko is strictly defined and limited under the Act and the normal terms of a compulsory pooling order to the costs which can be recovered from the sale of production from the well.

The examiners recognize Mr. Lazarenko's concern to know the costs attributable to his tract as soon as possible, however, the examiners agree with Voyager's contention that reasonable time should be allowed to compile and provide Mr. Lazarenko with a firm statement of those costs. The examiners observe that each party is responsible for its share of the actual costs of drilling, completing, operating, and abandoning the well as set out in section 72, subsection (4), clause (d) of the Act. The drilling and completing costs may soon be determined and the applicant will be in a position shortly to advise Mr. Lazarenko, in writing, of the actual amount. If the parties do not agree to the amount, an application may be made to the Board, pursuant to section 75(2), to have the costs set. The examiners therefore conclude that it would neither be necessary nor appropriate to specify such costs in an order should such an order be issued.

5 RECOMMENDATION

The examiners recommend that:

- the Board, with the approval of the Lieutenant Governor in Council, issue an order under section 72 of the Oil and Gas Conservation Act that all tracts within section 19, township 53, range 17, west of the 4th meridian, be operated as a unit for the production of gas from the Viking Formation,

- the order specify that the allocation to each tract of costs and production be based on the relationship of its area to the total area of the drilling spacing unit, and

- the order specify that if the non-participating party's share of costs is not paid within 30 days of receipt of the statement of costs or the issuing of the order, whichever is the later, a penalty in the form of interest at the rate of prime plus 1 per cent as of the date of issuing the order or the date of the issuance of the statement of the drilling and completion costs, whichever is the later, on the amount owing be assessed.

The amount payable as interest should not exceed 50 per cent of the non-participating party's share of the actual costs of drilling and completing the well.

DATED at Calgary, Alberta, on 13 September 1982

G. A. Warne, P.Eng.

J. R. Nichol, P.Eng.

D. Holgate

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

TRANSALTA UTILITIES CORPORATION
240-kV TRANSMISSION LINE
LAMOUREUX TO DEERLAND AND
DEERLAND SUBSTATION
FORT SASKATCHEWAN AREA

Decision 82-34
Application 820371

The Board has reviewed the report of its examiners, attached hereto, respecting Application 820371 for approvals to construct and operate 240-kV transmission facilities in the Fort Saskatchewan area. The Board agrees with the findings and recommendations of the examiners and will issue the appropriate permits and licences to construct and operate the applied for facilities.

The Board notes that the 240-kV transmission facilities form an integral part of the planning and development of the transmission system to supply the rapidly growing electrical requirements of the Fort Saskatchewan and northeast Alberta areas. For this reason, the Board believes there will be considerable interest in this report and is giving it a more widespread distribution than would normally be the case.

DATED at Calgary, Alberta, on 29 October 1982.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy
Vice Chairman

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

TRANSALTA UTILITIES CORPORATION
240-kV TRANSMISSION LINE
LAMOUREUX TO DEERLAND AND
DEERLAND SUBSTATION
FORT SASKATCHEWAN AREA

Examiners' Report E82-14
Application No. 820371

1 THE APPLICATION

TransAlta Utilities Corporation (TransAlta) applied pursuant to sections 12, 14, 16, 17 and 18 of the Hydro and Electric Energy Act for permits to construct and licences to operate approximately 31 kilometres of 240-kV double-circuit steel-tower transmission line from the existing Lamoureux substation 71S to a proposed 138-kV Deerland substation 13S (see Figure 1). The two circuits would initially be energized at 138 kV and would be designated as circuits 842L and 843L. Approval was also requested for the construction and operation of the Deerland Substation 13S and for alteration to Lamoureux substation 71S to accommodate the proposed line.

2 THE HEARING

The application was considered at a hearing on 22 June 1982 in Edmonton by Board appointed examiners R. G. Evans, P.Eng., H. J. Webber, P.Eng., and T. F. Homeniuk, P.Eng.

The following table lists the parties who appeared at the hearing.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
TransAlta Utilities Corporation (TransAlta) H. M. Kay	M. D. Rogers, P.Eng. W. A. Hosie, P.Eng. B. P. Scoble
D. Hoyda	D. Hoyda
C. Lamoureux	C. Lamoureux
A. Lamoureux R. Lamoureux	R. Lamoureux
Chevron Canada Limited (Chevron) W. H. Fraser	
Northcorp Development Inc. K. D. Wakefield	
Alberta Power Limited (Alberta Power) K. D. Wakefield	W. J. Beckett, P.Eng.
Estate of P. Hauer S. Radke	
Texaco Canada Resources Ltd. (Texaco) S. Murray	
H. Veltman D. B. Roth	
Shell Canada Limited (Shell) S. Brown	
Province of Alberta (Province) A. R. Watson	
Energy Resources Conservation Board staff K. Miller T. Chan, P.Eng. D. Beamer, C.E.T.	

Bill and Elizabeth Matthews filed a submission but did not appear at the hearing.

3 THE ISSUES

The examiners find that the issues to be considered are:

- o the need for the transmission line and substation;
- o the location of the substation; and
- o the route of the transmission line.

4 NEED FOR THE FACILITIES

4.1 Views of the Applicant

TransAlta stated that the firm capacity of the existing 138-kV transmission system supplying the northeast Fort Saskatchewan area from Lamoureux and Fort Saskatchewan is approximately 115 MVA. By mid-1983, the Shell Scotford refinery as well as the Shell Nova styrene plant would commence commercial operation and the Esso chemical plant at Redwater would require additional electric power. These developments would boost the areas' electricity demand to 198 MVA by 1983/1984. Other major industrial projects are expected to develop in the period 1984 to 1990. Therefore the existing 138-kV system supplying the northeast Fort Saskatchewan area would have insufficient capacity for 1983 and beyond. To provide the necessary capacity, TransAlta proposed to construct a double-circuit 240-kV transmission line from Lamoureux substation 71S to the proposed Deerland substation 13S, which would be established as a strong source to support the area.

To meet the mid-1983 load, TransAlta proposed to add a 240/138-kV transformer at the Lamoureux substation, construct a double-circuit 240-kV line from the Lamoureux substation to a point on the existing 138-kV line 706L north of Scotford, split up 706L and interconnect the bisected ends (re-designated as 810L) with the proposed double-circuit line, thus forming two circuits from Lamoureux (figure 2). Both circuits would initially be energized at 138 kV. The northern circuit would reinforce the supply to Esso Chemical, whereas the southern circuit would add another 138-kV source to the Shell Scotford refinery and Shell Nova styrene plant. Thus the immediate need for electric energy in the area would be satisfied.

In 1985, the proposed double-circuit line would be extended from the 810L intersection point to the proposed Deerland substation. Both circuits would then be disconnected from line 810L but would remain energized at 138 kV from Lamoureux substation, as before, until such time as the load warrants raising the voltage to 240 kV. Future 138-kV transmission lines would extend from the Deerland substation directly to the Redwater area and indirectly to the Scotford area via Bruderheim. The northeast Fort

Saskatchewan area would then be served by two major substations, Deerland on the east and Lamoureux on the west (figure 3), providing good reliability of supply to the area.

TransAlta submitted that Deerland would also be strategically located to supply loads that might develop in the Skaro industrial area and as a stepping-off point to supply power to northeastern Alberta. The transmission capacity in the Westlock - Lac La Biche area will need reinforcement by 1985 and, at some time later in the 1980s or early 1990s, a 240-kV line to Fort McMurray will be required. TransAlta stated that its long-range plan for meeting future demands in northeastern Alberta included a 240-kV line from the Deerland substation to Craigend, near Lac La Biche. A 138-kV line would then be constructed to Lac La Biche to reinforce the supply there. To meet Alberta Power's projected load increases in the Cold Lake area a 240-kV line would be constructed from Craigend to Cold Lake.

4.2 Views of the Interveners

Alberta Power supported the application, stating that the facilities applied for were consistent with long-range planning of transmission facilities to northeast Alberta. Its recent forecast shows that the load development would likely be centred in the Cold Lake rather than the Vegreville - Lloydminster area. It confirmed TransAlta's statement with respect to load forecast in the Cold Lake area. Alberta Power elaborated that 25 to 30 megawatts would probably be required in the next eight years for three or four small-scale oil-sands plants, and 50 megawatts for a heavy-oil upgrading plant. It also submitted that introduction of a high-capacity transmission line into the Cold Lake area would partially unload existing transmission lines to the Vegreville - Lloydminster area, and indirectly increase the availability of supply to those areas.

Shell supported the application, stating that the proposed facilities would improve reliability of supply to its refinery and styrene plant.

None of the other interveners questioned the need for the transmission line or substation.

4.3 Views of the Examiners

Having considered the information in the application and the evidence presented at the hearing, the examiners are satisfied there is a need for the proposed 138-kV transmission circuits and modifications to the Lamoureux substation to serve the firm loads expected in 1983. The examiners are also satisfied that load development in the northeast Fort Saskatchewan area and northeastern Alberta will require future 240-kV development. The proposed Deerland substation, in the examiners' view, is an appropriate terminal for the 240-kV line from Lamoureux substation and would provide an origin for future transmission expansion to northeastern Alberta.

The examiners conclude that the proposed 240-kV line, initially energized at 138 kV and interconnected with line 706L, is required. The

modifications at Lamoureux substation and the proposed Deerland substation are also required as terminals for the line.

5 LOCATION OF THE DEERLAND SUBSTATION

5.1 Views of the Participants

TransAlta stated that it has an option to purchase the property proposed as the location of the Deerland substation. It stated that the substation site offered reasonable access for construction, maintenance and operation and for future transmission lines. The site is screened from the local roads and highway and is not close to any residences.

The applicant stated that it had investigated other sites east of the proposed site and further away from the established natural areas. However, because of existing pipelines, gravel pits, oil-field operations, AGT facilities, drainage and foundation problems, and access for future transmission lines, these sites were not considered as acceptable as the site proposed.

None of the interveners commented on the site selected for the proposed Deerland substation.

5.2 Views of the Examiners

The examiners are satisfied that the Deerland substation site is a suitable location.

6 ROUTE OF THE TRANSMISSION LINE

TransAlta proposed a preferred route for the transmission line, together with an alternative for each of three different segments of the route. The routes are shown in Figure 1. TransAlta stated that the preferred and alternative routes are better than any other possible routes for the following reasons:

- o the routes would utilize, for over two-thirds of the length, zoned industrial areas and low-capability soils, thereby minimizing the effect on agricultural, residential and recreational land use;
- o existing linear facilities such as railroads, transmission lines and pipelines, would be parallelled wherever appropriate;
- o the proposed routes are as short and direct as any other possible routes from Lamoureux 71S to Deerland 13S; and
- o TransAlta has negotiated agreement for right of way for approximately 11 km of the preferred route.

Segment A1 to A6

TransAlta stated that the line on segment A1-A6 of the route would be located on right of way that it owned. The line would parallel an existing 138-kV line and for part of the segment it would also parallel the CN railway and existing pipelines.

The examiners believe this proposed segment of the route is appropriate.

Segment A6 to C1

TransAlta proposed that the line continue to follow the CN railway, crossing from the west to the east side of the railway near point A8. Existing pipelines and a proposed Texaco pipeline also parallelling the railway require the transmission line to be located some 45 metres east of the railway right of way.

Having examined the photomosaics provided in the application, and having regard for the constraints to routing a transmission line in this area, the examiners are satisfied that the proposed route between A6 and C1 is appropriate.

Segment C1 to Q4

TransAlta proposed two routes between C1 and Q4, its preferred route C1-A12-Q4 and an alternative C1-Q2-Q4. C1-Q2-Q4 is somewhat shorter, would have fewer corner structures, and would cost some $450 000 less to construct. However, the line would be located some 45 metres east of the railway right of way because of existing and proposed pipelines next to the railway. This effectively would place the transmission line structures well into the adjacent cultivated fields and impose an impact on farming operations. TransAlta therefore preferred route C1-A12-Q4.

The North Saskatchewan River crossing between C1 and A12 would be longer and at an angle more oblique than the crossing between Q2 and Q4. While the line had not yet been designed, TransAlta suggested that a tower would likely be placed on the lower flood plain on the east side of the river, thus avoiding the need to span the entire valley.

TransAlta stated that between A12 and Q4 the line would be located on property owned by Shell with whom it had already reached an agreement.

Mr. C. Lamoureux and Mr. R. Lamoureux opposed the alternative route between points C1 and Q2. They contended that the towers would be located in the headlands of their fields and would interfere with the operation of their farm equipment, particularly while turning the equipment, as is done in the headlands. They further suggested that the line should be located along fence lines to minimize the impact on farming operations.

Mr. Hoyda requested that the Board reject the applicant's preferred route between C1-A12-Q4 because of the higher cost, which would be passed on to consumers. Furthermore, crossing the river between C1 and A12 would have a detrimental effect on the aesthetic value of the river valley. This, he

contended, would destroy the potential for the country residential development that he was considering for his land.

The examiners note that the alternative would essentially be a diagonal route across 5.0 km of cultivated land, even though it parallels the railway and pipeline rights of way. The centreline of the transmission line would be approximately 45 metres from the boundary of the CNR right of way, placing the structures well into the cultivated fields. The Board has expressed the view several times, and the examiners agree in this instance, that such tower placement has a much greater impact on farming than a "field edge" placement, and should be avoided wherever possible.

Segment C1 to A12 of the preferred route traverses a shorter length (2.4 km) of cultivated land and sod farm, but in this situation the structures would straddle the quarterline, thus minimizing the effect on the farming operation. The examiners also note Mr. Hoyda's statement that the transmission line would not hamper the sod-farming operation. The remaining portion A12 to Q4 of the preferred route is located on Shell property which is zoned for industrial purposes.

Although the river crossing on the preferred route would be longer than on the alternative route, there are no engineering constraints or significant problems associated with either one. Although Mr. Hoyda spoke of potential subdivision development, no definite plans have been prepared or applications filed to effect this. In the examiners' judgement this uncertainty, combined with the probability that there would be some considerable distance between the line and such a subdivision development, leads to the conclusion that no definite advantage or disadvantage can be ascribed to either route because of visual impact at the river crossing.

Construction costs for the preferred route are indicated to be $425 000 greater than for the alternative route. However, a true and complete evaluation should also consider the land costs, land and crop damage during construction, loss of agricultural production and long-term impact on farm operating costs, all of which would be greater for the alternative route. Insufficient evidence was adduced to allow the examiners to quantify these matters precisely, but the total cost, while still expected to be greater for the preferred route, would be so by an amount less than $425 000.

The examiners find that the two routes differ significantly in only two respects. Segment C1-Q2-Q4, shorter and less costly, would be located for some 5 km on cultivated land and would therefore result in a significant impact on farming. Segment C1-A12-Q4 is somewhat longer and more expensive but would place the line on the edge of an industrially zoned area for a good portion of the route. The examiners believe that the higher cost of segment C1-A12-Q4, the applicant's preferred route, is justified to remove the line from the cultivated area between points C1 and Q4.

Segment Q4 to A24

TransAlta stated the route between Q4 and A24 would parallel the quarter line and that the portion from Q4 to Q7 would be located on Shell property, for which agreement had already been reached.

The examiners find this portion of the route appropriate.

Segment A24 to D24

TransAlta proposed three alternatives for this portion of the route. Its preferred route, A24-A25-A28-D16-D24, would follow the boundary of an area zoned for industrial use. Some 3.2 km of the route is located on land owned by Chevron, for which agreement has been reached.

The alternative route, A28-A34-D24, would bisect an area designated by Alberta Energy and Natural Resources as a natural area. Also, immediately north of point A28, the line would be located near an oil battery site owned by Texaco. The alternative A24-D15-D24, would follow quarter and section boundaries. TransAlta indicated that some increase in construction costs would be involved near point D15, which is a low-lying wet area.

Mr. D. Roth, representing Mrs. H. Veltman, suggested in argument that TransAlta's preferred route should be approved, thus locating the line at the boundary of the industrially zoned area rather than through it.

The examiners are satisfied that TransAlta's route, A24-A25-A28-D16-D24, is acceptable.

Segment D24 to S3

TransAlta proposed only one route for this portion of the line. The line would be located south of the quarter-section line from D24 to H1 to reduce tree removal and to minimize the visual impact in the area of Mr. & Mrs. Matthews' residence. The remaining portion of the line, from H1 to S3, would straddle the quarter line. The route would have a small southerly deflection in the SE1/4-24-56-21-W4M to avoid Esso's oil battery located immediately north of the quarter line. TransAlta stated it could not deflect the line north around the battery because of several wells and a radio transmitter located north of the battery.

Mr. Radke, representing the estate of P. Hauer, suggested the line be routed north of Esso's battery site.

The examiners find the proposed route acceptable. They agree that the deflection in the route around the battery site is necessary and believe the deflection to the south would have little or no impact compared to deflection to the north. The examiners are also satisfied that locating the line south of the quarter-section line would reduce the amount of tree clearing, hence the visual impact of the line near the Matthews' residence.

7 RECOMMENDATIONS

The examiners recommend that the application be approved as follows:

- The Deerland substation be approved for construction on the site applied for.

- The transmission line be approved for construction on the preferred route (A1-C1-A12-Q4-A25-D16-D24-Q40-S3).

- The alteration to the Lamoureux substation be approved.

DATED at Calgary, Alberta, on 18 October 1982.

R G Evans

R. G. Evans, P.Eng.

H J Webber

H. J. Webber, P.Eng.

Homeniuk

T. F. Homeniuk, P.Eng.

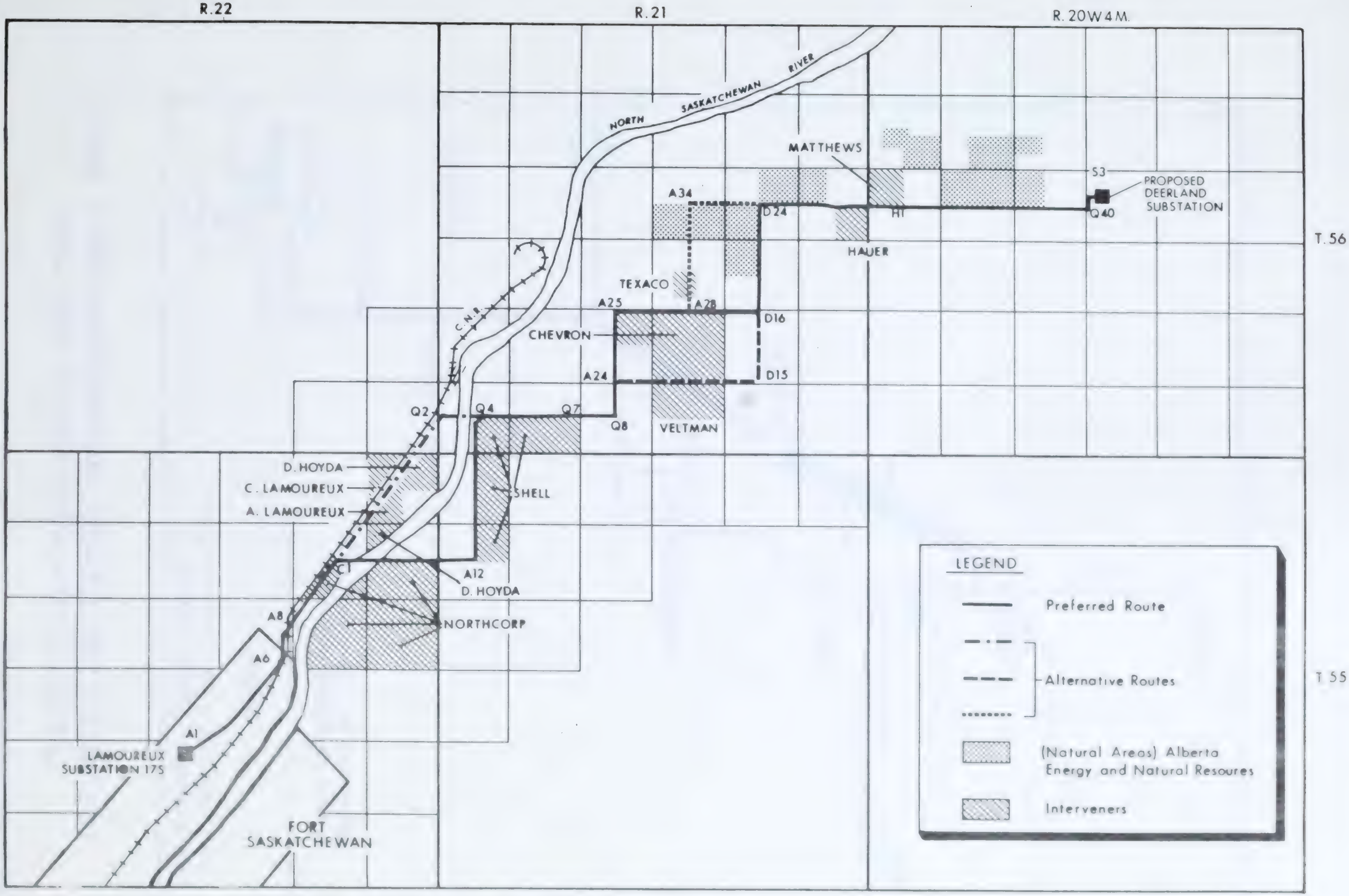


FIGURE 1 PREFERRED AND ALTERNATIVE ROUTES FOR THE 240-kV TRANSMISSION LINE.

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA CANADA

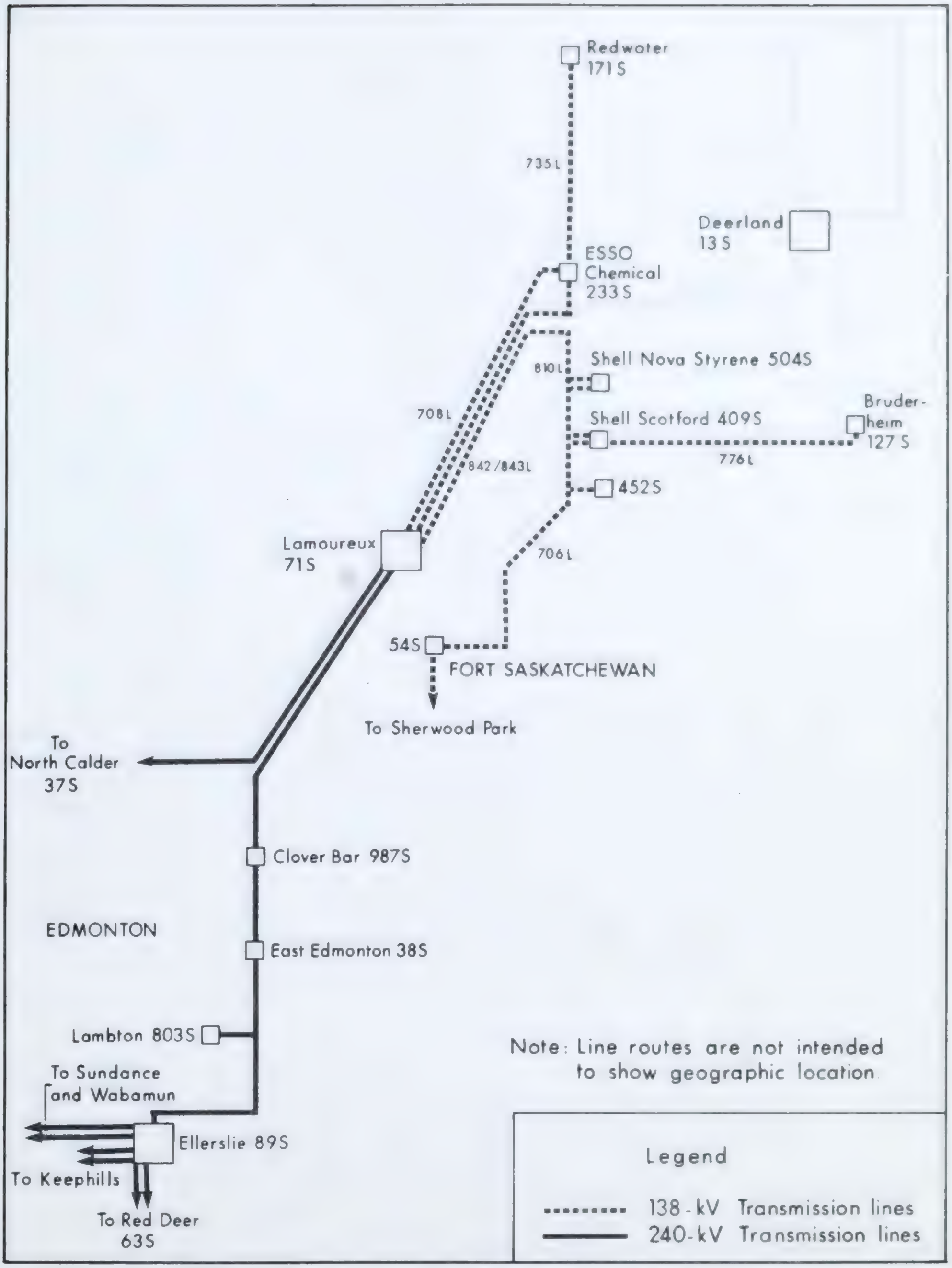


FIGURE 2 FORT SASKATCHEWAN AREA ELECTRIC SYSTEM - 1983
(After Figure SKT-1516 of TransAlta's application)

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

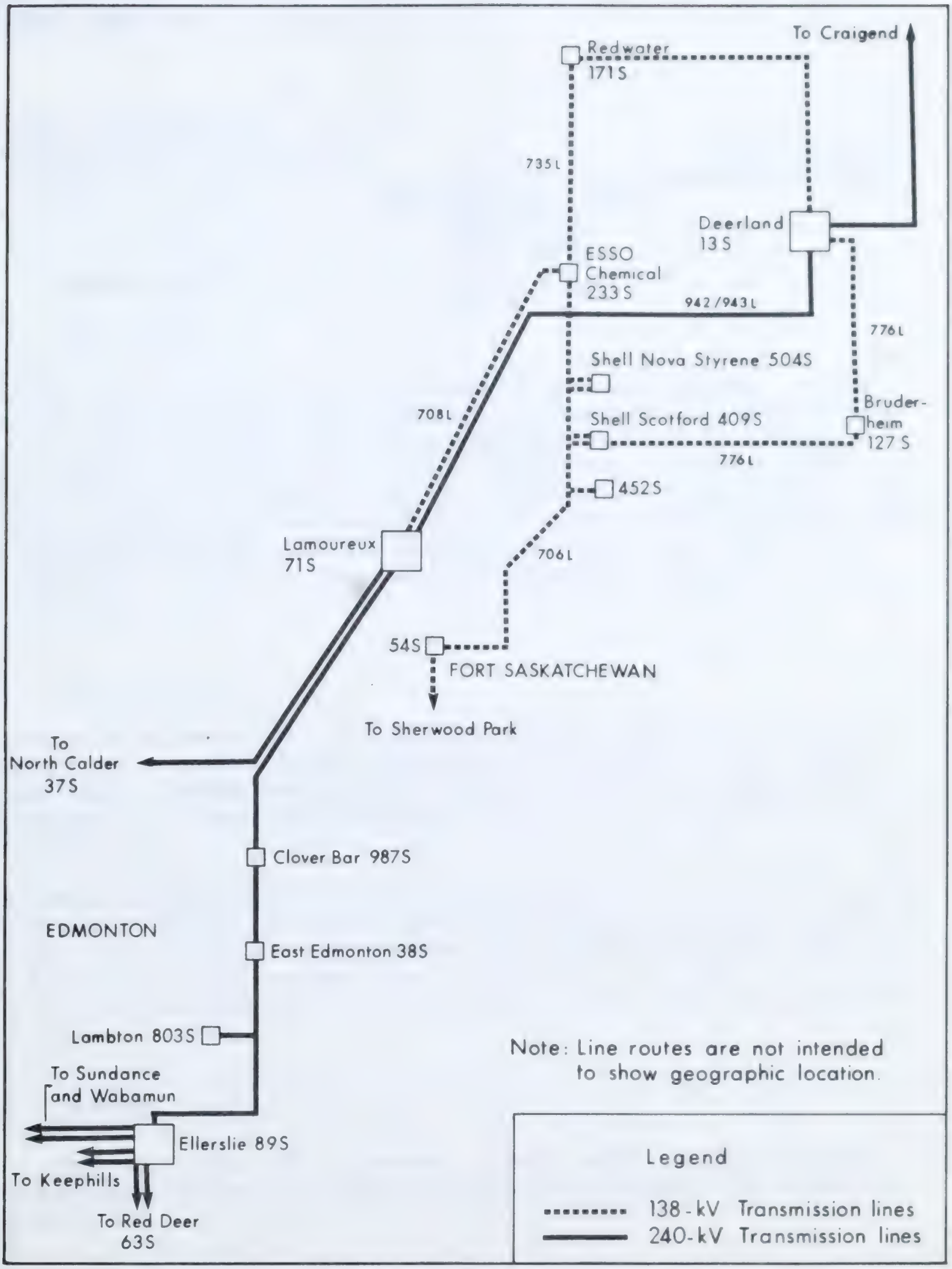


FIGURE 3 FORT SASKATCHEWAN AREA ELECTRIC SYSTEM -1985
(After Figure SKT-1516 of TransAlta's application)

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

PASSBURG PETROLEUMS LTD.
SECONDARY NATURAL GAS PIPELINE
CALMAR AREA

Decision 82-35
Application 820949

1 INTRODUCTION

1.1 Application

Passburg Petroleums Ltd. (Passburg) applied pursuant to Part 4 of the Pipeline Act, for a permit to construct approximately 2 kilometres (km) of 114.3-millimetre (mm) outside diameter (OD) pipeline to transport sweet natural gas from a well in legal subdivision 7 of section 36, township 49, range 27, west of the 4th meridian (the 7 of 36 well) to an existing Passburg pipeline located in Lsd 7-35-49-27 W4M. Figure 1 shows the applied-for route, the 7 of 36 well, the Calmar town limits, and certain other features of interest with respect to the subject application.

1.2 Interventions

Landstrom Developments Ltd. (Landstrom) stated a belief that Passburg's proposed route would restrict development of a portion of its proposed subdivision if development setbacks from the well and pipeline were implemented. It suggested alternative routes having less impact on its subdivision.

The Town of Calmar (Town) expressed a concern that the proposed pipeline would result in lost tax revenue and pose a health and safety hazard. It was also concerned about the pipeline right of way width, and right of way maintenance after construction. It stated a view that the 7 of 36 well and the existing Dome Petroleum Limited (Dome) pipelines should be relocated.

1.3 Hearing

G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and E. J. Morin, P.Eng., heard the application at a public hearing on 3 November 1982 in Calmar, Alberta.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Passburg Petroleums Ltd. (Passburg) F. M. Saville	L. Schnitzler, P.Eng. G. Hannah, Petro-Line Construction Canada Ltd. M. Wall, ICG Utilities (Plains-Western) Ltd. D. M. Leahey, Western Research and Development
Landstrom Developments Ltd. (Landstrom) M. J. Sychuk, Q.C. N. Stefaniuk	M. D. Sanderson, Deleuw Cather, Western Ltd.
Town of Calmar (Town) B. Tremblay M. Blazenko	B. Tremblay
Energy Resources Conservation Board staff D. G. Holgate H. W. Knox, P.Eng. S. P. Angrave	

1.4 Procedural Matters

At the hearing, Landstrom's solicitor Mr. Sychuk, raised two matters which in the Board's view, require further comment. The first was a motion to have the evidence of the applicant's witnesses given under oath. The Board indicated it was not the Board's usual procedure to require that evidence be given under oath, and since there were no unusual circumstances in the present case, the Board saw no reason to depart from its normal practice. The motion was denied.

The second matter was a request that, if the Board approved the application, the approval contain a condition, pursuant to section 11(2) of the Pipeline Act, that the applicant "acquire any interest in land not owned by him and required for the purposes of his pipeline by negotiation with the owner." This matter will be dealt with further in section 5 of this report.

2 ISSUES

The Board considers the issues to be:

- o the need for a pipeline,

- the impact and routing of the pipeline, and
- construction permit conditions if the application is approved.

3 NEED

3.1 Applicant's Views

Passburg stated that the reserves underlying section 36 amount to approximately 140×10^6 cubic metres (m^3). It has a deliverability-type contract with ICG Utilities (Plains-Western) Ltd. to deliver 140.9×10^3 m^3/day for the anticipated life of the system of 15 to 20 years. It indicated that the 7 of 36 well represents a major portion of the gas supply for the contract.

Mr. Wall, appearing on behalf of Passburg, indicated that ICG Utilities would have to purchase gas from Northwestern Utilities Limited to make up the difference between the demand and Passburg's reduced supply if the 7 of 36 well was not brought on stream. This would result in a 6 to 7 per cent increase, some $600 000 per year, in the price of gas to Calmar and Leduc consumers.

Passburg stated that the location of the 7 of 36 well had been agreed to by the Town in 1976.

3.2 Interveners' Views

Landstrom did not question the need for the pipeline.

While the Town did not question the need for the gas supply for the area's consumers, it did question the need for the proposed pipeline and production from the 7 of 36 well, and stated that the well and pipeline would seriously affect expansion of the town. In its opinion the 7 of 36 well should be directionally re-drilled and the existing Dome pipelines relocated.

3.3 Board's Views

The Board is satisfied that Passburg has rights to the mineral reserves under section 36 and believes those reserves to be substantial. It also believes that a significant portion of the reserves would not be recoverable from other existing wells if the 7 of 36 well was not produced. It notes that Passburg has an agreement to supply gas to ICG Utilities but will be unable to meet its contract without production from the 7-36 well.

The Board notes not only the Town's request to have the 7 of 36 well and the existing Dome pipelines relocated outside the Town limits, but also, that the Town did not present detailed evidence supporting its request, nor did it discuss the financing of the relocations. Landstrom, which owns the lands on which the 7 of 36 well is located, did not request its relocation. The evidence at the hearing indicated that there would be a substantial effect of not connecting the well on the consumer price of gas. The Board also notes the 1976 letter (Exhibit 20) wherein the Town agreed to the 7 of 36 well location. For these reasons the Board concludes there is a need to connect the 7 of 36 well providing the impacts are not unacceptable. These impacts will be dealt with in some detail in the next section of the report.

4 IMPACT AND ROUTING

4.1 Description of Routes

Figure 2 shows five routes that were discussed at the hearing:

- Route A is the route proposed by Passburg in its application. The proposed pipeline would proceed from the 7-36 wellhead in a northwest direction (on Passburg's surface lease) to the south side of the existing Dome right of way in the SE 1/4 of section 36. The Passburg line would parallel the existing Dome pipelines in the Dome right of way with approximately a 4.1-metre (m) separation between the Dome and Passburg pipelines. The Passburg line would then proceed west to a tie-in point at 7-35-49-27 W4M (7 of 35).

- Route B is an alternative route suggested by Landstrom at the hearing. The route proceeds north from the 7 of 36 wellhead into the NE 1/4 of 36, north of the existing Dome pipelines. It would then parallel on the south side, an existing sewage line right of way until intersecting a Texaco Canada Resources Ltd. (Texaco) right of way. It would parallel that line in a south westerly direction, recross the Dome pipelines, and then proceed west to the 7 of 35 tie-in.

- Route C is another alternative suggested by Landstrom at the hearing. This route would proceed north, west, and south, around the sewage disposal site area as shown on Figure 2. It would then follow the Dome pipelines west to the tie-in 7 of 35.

- Route D is an alternative which Passburg said it evaluated during its negotiations with Landstrom prior to the hearing. It proceeds north of the 7 of 36 well into the NE 1/4 of section 36, west along the north side of the quarter section boundary

immediately adjacent to the sewage lagoon, south to the Dome pipeline right of way, across those pipelines, and then west to the 7 of 35 tie-in.

- Route E is a route which Passburg said at the hearing is acceptable. The route proceeds north to the boundary of Passburg's surface lease, then west within the lease until it crosses the Dome pipelines. It would then parallel the Dome lines, with approximately 4.5 m separation between the pipelines, west to the 7 of 35 tie-in.

4.2 Applicant's Views

Passburg stated that route A is the shortest, most economical to construct (approximately $50 400), and uses only existing leases and right of ways. It indicated that it had obtained a tentative agreement with Dome for a 1-m easement (plus a 3-m working space) within and on the south side of the existing Dome right of way. It indicated that Dome preferred that its pipelines not be crossed by the proposed line. Passburg said that it would bring in additional topsoil to restore the surface after pipeline construction.

Passburg stated that the proposed pipeline would be designed to a Canadian Standards Association CSA-Z184 Gas Pipeline Systems class 3 location and would not require upgrading should the Landstrom subdivision be approved.

Dr. Leahey, in rebuttal for Passburg, indicated that the risk from the proposed pipeline and the existing Dome pipelines is minimal; not warranting the setbacks assumed by Landstrom in presenting its evidence regarding the possible subdivision.

Passburg stated that it had evaluated several other routes for the pipeline but believed them to have more impact on the area than the proposed line. During questioning it discussed several alternative routes, including B, C, D, and E as shown on Figure 2. Passburg indicated that route C would involve additional creek and pipeline crossings, be significantly longer, resulting in a larger pressure drop, and would cost three times the amount for a line on route A. Route D, it stated, would be more expensive, require additional negotiations with surface owners, and be unacceptable to the Town because it would pass in close proximity to the Town's sewage lagoon.

Passburg said route B was also longer and would involve crossing the Dome pipelines, require routing the lines through the existing sewage disposal site (parallel and adjacent to the existing Texaco line), and require negotiations with other surface landowners.

At the hearing Passburg indicated that a route parallel to and north of the existing Dome pipelines was acceptable to it, providing it did not leave the Dome right of way. In addition, it stated that any alignment from the 7 of 36 wellhead to the Dome right of way within its surface lease was acceptable to it. Route E represents an example of such a route.

4.3 Interveners' Views

Landstrom

Landstrom stated that, while it had not received final approval for its proposed subdivision, it had received approval of its outline plan from the Edmonton Metropolitan Regional Planning Commission (EMRPC).

M. Sanderson, appearing for Landstrom, stated that Landstrom had evaluated the impact of the proposed Passburg pipeline on the planned subdivision. For the evaluation it used a Town-recommended 30.5-m development setback from the proposed pipeline and a EMRPC recommended 61-m development setback from the 7 of 36 well. On this basis, the proposed line would affect 30 lots. It also stated it had compared the impact of several alternative routes, and had even considered redesign of the subdivision to minimize the effects from pipeline setbacks. However, it stated that such redesign was "not ... a solution to the problem" and stated that a route north from 7 of 36 well out of the SE 1/4 of 36 was most acceptable to Landstrom. To this end it proposed routes B, C, and D (Figure 2). In argument, it stated that it preferred route E over route A if a route following the existing Dome pipelines within section 36 were to be approved.

In support of route B, Landstrom stated that this route was acceptable to the Town and would not affect the existing sewage site. It also indicated that route D would not impact the Town's sewage lagoon. It did not comment on the appropriateness of route C, although it questioned the applicant respecting the possibility of such a route.

Landstrom stated that the development setbacks suggested by the Town and the EMRPC provided a factor of safety for residents. It noted that the EMRPC suggested a 15-m setback for the existing Dome pipelines but believed the setback to the proposed Passburg line would override it. Landstrom agreed it would be reasonable to assume that both the Dome and Passburg lines should have similar setbacks, but stated that the EMRPC made the final decision regarding setbacks.

Landstrom stated that, while its subdivision was within the 305-m sewage lagoon setback required by The Planning Act, 1977, it believed the Town's proposed mechanical sewage treatment plant would be located further north, minimizing any effects from that setback. In its opinion such setbacks were flexible.

Landstrom stated that it had reviewed the impacts to its subdivision by selectively applying potential setbacks. For example, it did not apply the potential 305-m sewage lagoon setback nor did it consider the extent of the existing Passburg surface lease. It indicated that it "is common practice in subdivision design" to selectively apply setbacks depending on whether or not the impacts can be minimized through modification of the feature causing an impact or redesign of the subdivision design itself.

Town of Calmar

The Town stated that it was opposed to the location of the existing well and proposed pipeline because the latter would reduce the number of available lots and would decrease the tax revenue to the Town once the subdivision is approved. It stated a belief that not only the proposed line, but also the existing Dome pipelines, would pose a potential health and safety hazard for the subdivision's future residents. Additionally, it expressed a view that parallelling the existing Dome pipelines would create a pipeline corridor which would affect future expansion of the town.

The Town stated that it had no definite policy about development setbacks and that if pipeline setbacks were implemented, they would probably apply to all pipelines.

The Town indicated that it plans to install a new mechanical sewage treatment plant north of the existing sewage disposal site with assistance from the Department of the Environment. It said that the town would probably have the necessary qualifying population in 5 or 6 years.

At the hearing, the Town initially indicated a preference for route D, if the line were to proceed, but then stated that Town council had endorsed its planning consultant's recommendation not to accept the route because of possible conflicts with existing sewage facilities. It did not indicate a preference for any other routes.

4.4 Board's Views

In assessing the routes discussed at the hearing the Board considered:

- impacts to and compatability with existing facilities such as the sewage disposal lagoon and site,

- impacts to the proposed subdivision including those that might relate to possible setbacks,

- health and safety considerations,

- other factors such as the creation of a pipeline corridor and the effect on the Town's tax revenue, and

- pipeline costs.

Existing Facilities

Upon reviewing the evidence, the Board is of the opinion that any of the routes discussed, except possibly route B, could be constructed within the existing infrastructure of the area. However, it believes that route D would be less acceptable in that it would pass in close proximity to the sewage lagoon. Passburg expressed doubt that route B could even be constructed through the sewage lagoon. The evidence from the Town on this matter was not clear, but apparently it believed these routes could be accommodated if essential. With regard to the remaining routes the Board believes they would have minimal impacts associated with them in so far as existing facilities are concerned.

Impacts to the Proposed Subdivision

When considering impacts to Landstrom's proposed subdivision in the SE 1/4 of section 36, the Board considered the possibility of development setbacks being implemented for the proposed and existing facilities in the area.

The Board knows of no Alberta Statute requiring development setbacks from sweet natural gas pipelines, such as suggested by the Town for the proposed Passburg pipeline. If setbacks were required for pipelines the Board expects that those setbacks would be similar for both the Dome pipelines and the proposed Passburg line. The Board also notes that an approved subdivision outline plan does not constitute a legal subdivision. Consequently, the Board has reviewed the evidence respecting the impacts from potential development setbacks, keeping in mind there is only a possibility of future subdivision of the area in question.

The Board believes routes B and C would have the least impact on the possible future subdivision, with or without development setbacks, simply because the majority of those routes are not within the SE 1/4 of section 36. Without devlopment setbacks, route D would have a similar impact as routes B and C, but with setbacks, it could affect the subdivision potential of the north and west extremes of the subject quarter section. Routes A and E would have similar and minor impacts if no development setbacks were considered. However, if setbacks were imposed at some future date and assuming they would be identical for the Dome pipelines and for the proposed Passburg pipeline, the Board is of the view that a route for the proposed line on the south side of the Dome lines would extend the prohibited development area further into the prime potential subdivision area than would a new line on the north side of the existing Dome lines.

The Board also considered for any future subdivision, the possibility of setbacks from other facilities in the area, specifically sewage lagoons and/or sewage treatment plants. Section 12(1) of the Subdivision Regulation (A. Reg. 132/78, as amended), pursuant to The Planning Act, 1977, indicates that the subdivision-approving authority shall not approve residential subdivisions within 305 m of a sewage treatment plant or a sewage lagoon. While no specific evidence was presented to evaluate the impact to Landstrom's subdivision from such a setback, the Board believes that a significant portion of Landstrom's proposed subdivision could potentially be affected. However, the Board also notes that the Town is considering installing a new mechanical sewage treatment facility to the north of the existing sewage disposal site when the town's population increases sufficiently to qualify for provincial funding assistance. The Town stated this could take up to six years but suggested that such a move would eliminate sewage lagoon-related restrictions on subdivision potential in the area. Additionally, Landstrom indicated these setbacks may be reduced if mitigating actions are taken.

For the above reasons, even though the development restriction related to the sewage lagoon would overlap and eliminate restrictions which might be imposed as pipeline setbacks, the Board has had regard for a possible future situation where pipeline setbacks exist but where restrictions respecting sewage facilities would have been removed.

Health and Safety Considerations

After reviewing the routes discussed at the hearing, the Board is of the opinion that the effects to health or safety from any of the proposed routes would be minimal and essentially the same. It notes that the proposed pipeline has been designed having regard for the possibility of future subdivision. Considering the Town's contention that the existing Dome pipelines should be relocated, the Board recognizes that the Town may choose at a future date to make an application under section 34 of the Pipeline Act for relocation. However, the information currently available to the Board indicates that the design of the existing Dome pipelines is adequate for the existing situation. The Board also notes that should this particular area be subdivided, resulting in a Zone 2 area, as defined in Canadian Standards Association code CSA-Z183 Oil Pipeline Transportation Systems, then Dome would be required to review the pipeline designs and upgrade to meet any Zone 2 requirements.

With respect to the safety implications of the possible crossings of existing pipelines by the proposed line, the Board believes that pipeline crossings of that nature are relatively routine and can be accomplished with minimal hazards.

Other Factors

The Board does not believe that locating a pipeline adjacent to the existing Dome lines for approximately 2 km would result in the creation

of a pipeline corridor to any greater degree than already exists. Respecting the Town's contention that tax revenue to it would be reduced if the proposed line were approved, the Board considers the incremental differences in land affected, in comparison to lands currently affected by existing facilities, to be minimal, and would therefore not have a substantial effect on potential tax revenue.

Costs

The Board considers the costs of the pipelines to be primarily dependent upon the length of route and the number of pipeline crossings necessary. Route C would be most costly whereas Passburg's proposed route A would be the least costly. Route E would be marginally more costly than route A and routes D and B would be progressively more costly.

Summary

The Board is of the view that the impacts of a pipeline connecting the 7 of 36 well and the existing gas gathering system are not so great as to cause denial of the application. The Board believes, however, that the route of the pipeline should be chosen to minimize these impacts.

The Board believes that the additional costs of route C cannot be justified by reduced impacts. Route B has the disadvantage of being questionable in terms of compatibility with the sewage lagoon and being somewhat more costly, without substantial benefits in reduced impacts. Route D would be more costly than certain other available routes, would possibly conflict with the sewage lagoon dike but particularily if future pipeline setbacks are assumed, would not have a substantially reduced impact on subdivision potential when compared to routes E and A. While the Board recognizes that route A has the advantage of being the least costly, it considers the location of the pipeline on the south side of the Dome right of way to have the potential for greater incremental impact to the Town of Calmar, its residents, and to a possible future subdivision if setbacks were imposed. This is because a new pipeline south of the existing Dome line, with an identical setback to that of the Dome lines, would extend the restricted development area south and east into the portion of the SE 1/4 of section 36 which is closest to existing residential developments and most crucial to an extended subdivision.

For all of the above reasons, the Board concludes that alternative route E, or a variation of it, would be the most appropriate one for the proposed pipeline.

The Board notes that Passburg indicated that it would accept any route between the 7 of 36 wellhead and the Dome right of way, providing that the route was located somewhere on its existing surface lease. Having that in mind, the Board recognizes that there are any number of routes

which would be within the existing surface lease and yet could reduce possible future impacts on subdivision by parallelling the Dome lines on the north side. The Board would consider such routes to be acceptable variations of route E.

5 CONSTRUCTION PERMIT CONDITIONS

The Board, having concluded in sections 3 and 4 of this report that a pipeline should be approved, is dealing in this section with the need or otherwise for special conditions in the pipeline permit to be issued.

5.1 Interveners' Views

Landstrom requested that the Board condition the construction permit, if granted, as follows:

- "(The Board)...use the provisions of section 15 of the Pipeline Act to specifically prescribe both the location of the pipeline, (and) the route of the pipeline,",

- "That the permittee shall be granted a license to operate the...pipeline only if it establishes that it has constructed the pipeline in the prescribed location and establishes that in constructing the...pipeline it has not trespassed on any of Landstrom's land.", and

- "Pursuant to section 11(2) of the Pipeline Act, the permittee shall acquire any interest in land that may be required for the purposes of its pipeline by negotiation with the owner and that section 48...of the Pipeline Act (preventing action under the Surface Rights Act) is therefore applicable to the permittee."

Landstrom stated that Passburg, during negotiations, had indicated the life of the 7 of 36 well to be 10 years. It believed a 10-year life would have less effect on its proposed subdivision than a 15- to 20-year life and therefore urged the Board to require accelerated production.

The Town requested that a condition detailing responsibility for right of way maintenance be attached to any permit issued.

5.2 Applicant's Views

In response to construction permit conditions requested by Landstrom, Passburg agreed that the Board should utilize its powers as outlined in section 15 of the Pipeline Act and "prescribe the location and route of the pipeline..." it determines to be best.

Passburg, however, found it unacceptable that the Board should withhold the licence to operate the pipeline should Passburg inadvertently trespass on Landstrom's land during construction. It stated that it would construct its pipeline in its 1-m right of way (plus 3-m working space) using a 2-m wide, rubber-tired R65 Ditch Witch machine for trenching, dragging in prewelded sections of pipe, and backfilling. Trespass might occur, particularily if frost were in the ground and the trencher had difficulty digging a straight line.

Passburg objected to Landstrom's suggestion that section 11(2) of the Pipeline Act, requiring a permittee to acquire interest in lands through negotiation; and section 48 of the Pipeline Act, preventing land acquisition through proceedings under the Surface Rights Act, should apply to its application. It stated that that would be discriminatory to Passburg.

Although the life of the 7 of 36 well might be reduced to 10 years by accelerated production, Passburg speculated that this might cause reservoir damage or reduced reserve recovery. It stated the life of the 7 of 36 well would be 15 to 20 years.

Passburg indicated that if it were necessary to cross the Dome pipelines, the crossings could be done safely. It stated that its working space adjacent to those lines would be fenced, ensuring safe construction practices.

Passburg stated that it did not intend to selectively strip topsoil along the route, but would bring in additional topsoil if requested. Passburg stated that right of way maintenance would remain with whoever is maintaining the Dome right of way.

5.3 Board's Views

The Board agrees that the location and route of the pipeline should be specified as a permit condition.

The Board does not believe it would be in the public interest to withhold a licence to operate a pipeline simply because during the construction of the line, a trespass occurred. It notes Passburg's intentions and construction plans to ensure this will not occur and would expect Passburg to use special construction equipment and procedures to safeguard against the possibility of trespass. If an inadvertent straying off the right of way did take place, the Board would expect to be advised of it and the reasons why it occurred, but, since provisions for compensation exist for such cases, would not withhold the operating licence.

With respect to the request by Landstrom that the permit direct Passburg to acquire any required interest in land by negotiating with the owner,

the Board does not believe that any special circumstances exist in this case to justify the applicability of section 48 of the Pipeline Act.

Considering the life of the 7 of 36 well and the concerns expressed by Landstrom, the Board believes that Passburg could, to a certain extent, minimize the life of the well by maximizing its rate of production. The Board encourages Passburg to do this to the extent that it is possible without causing reservoir damage and a reduction to the ultimate recovery of the gas under section 36.

Although the requirements of possible pipeline crossings were not discussed in detail at the hearing, the Board is of the view that, provided existing regulations are adhered to, pipeline crossings can be accomplished in a safe and satisfactory fashion. It believes, however, that in the event the Dome lines are crossed, additional discussions between Dome and Passburg would be useful.

Concerning topsoil reclamation, the Board notes Passburg's undertaking to bring in additional topsoil to mitigate subsoil mixing if requested.

The Board considers right of way maintenance to be the responsibility of the owner of the right of way. To alleviate the Town's concerns, the Board intends to notify the Land Reclamation Council of the construction of the pipeline to ensure that ongoing maintenance is satisfactory.

6 DECISION

The Board is prepared to approve a pipeline which would proceed diagonally from the 7 of 36 well to the existing Dome pipelines, as proposed by the applicant, but, for the reasons expressed in section 4, would require that it cross the existing lines and parallel them on the north side rather than the south side. The intended route of the diagonal portion of the line is that which would be perpendicular to the Dome lines and thus would be the shortest route between the 7 of 36 well and the Dome pipelines. The Board recognizes that there are a number of possible routes that would involve a line which would be more or less directly from the well to the Dome lines, and across those lines to parallel them on the north side. If Passburg and Landstrom were to agree to such a route, and so inform the Board, the Board would specify such route in the pipeline permit rather than the one described above. The Board will issue the permit as soon as Passburg has advised it as to whether or not Passburg and Landstrom have agreed to a modification of the route set out in the preceding paragraph and provided the Board with a detailed plan so that the location can be specifically setout.

The following conditions will be part of the permit to construct:

CONDITIONS

1. The route location will be specified.

2. Passburg will be required to notify the Board's Edmonton Area Office at least 24 hours prior to commencement of construction.

3. Passburg will be required to immediately advise the Board of any trespass onto Landstrom lands that may occur during construction, stating the reasons for the trespass.

4. A representative of Dome will be required to be present during the crossing of the Dome pipelines.

5. The Dome lines will have to be located and staked prior to construction. The extent of Passburg's right of way and working space in section 36 will also be surveyed and staked.

DATED at Calgary, Alberta on 23 November 1982.

G. J. DeSorcy

G. J. DeSorcy
Vice Chairman

C. J. Goodman

C. J. Goodman
Board Member

E. J. Morin

E. J. Morin
Acting Board Member

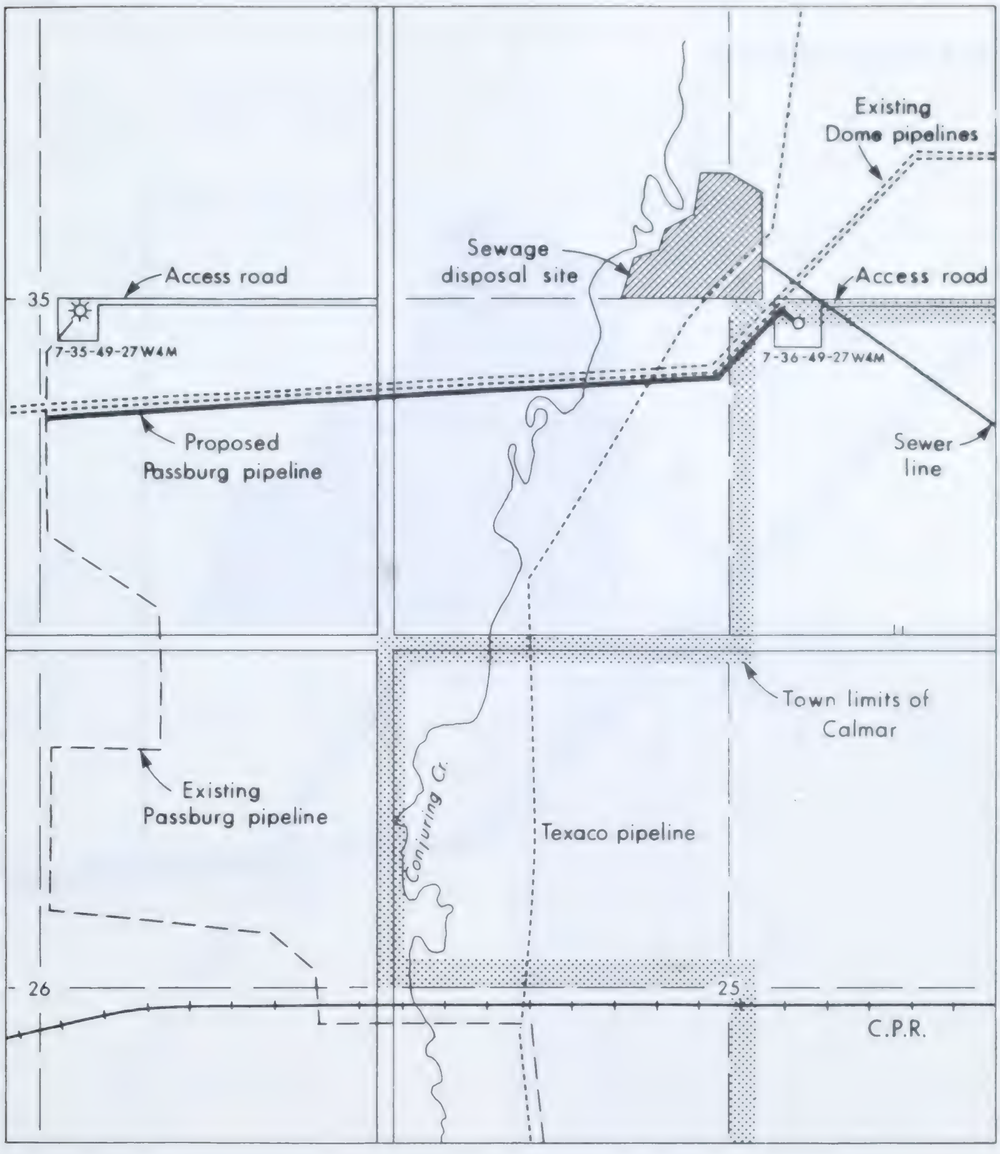


FIGURE 1 PROPOSED PASSBURG PETROLEUM LTD. PIPELINE IN THE CALMAR AREA

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA CANADA

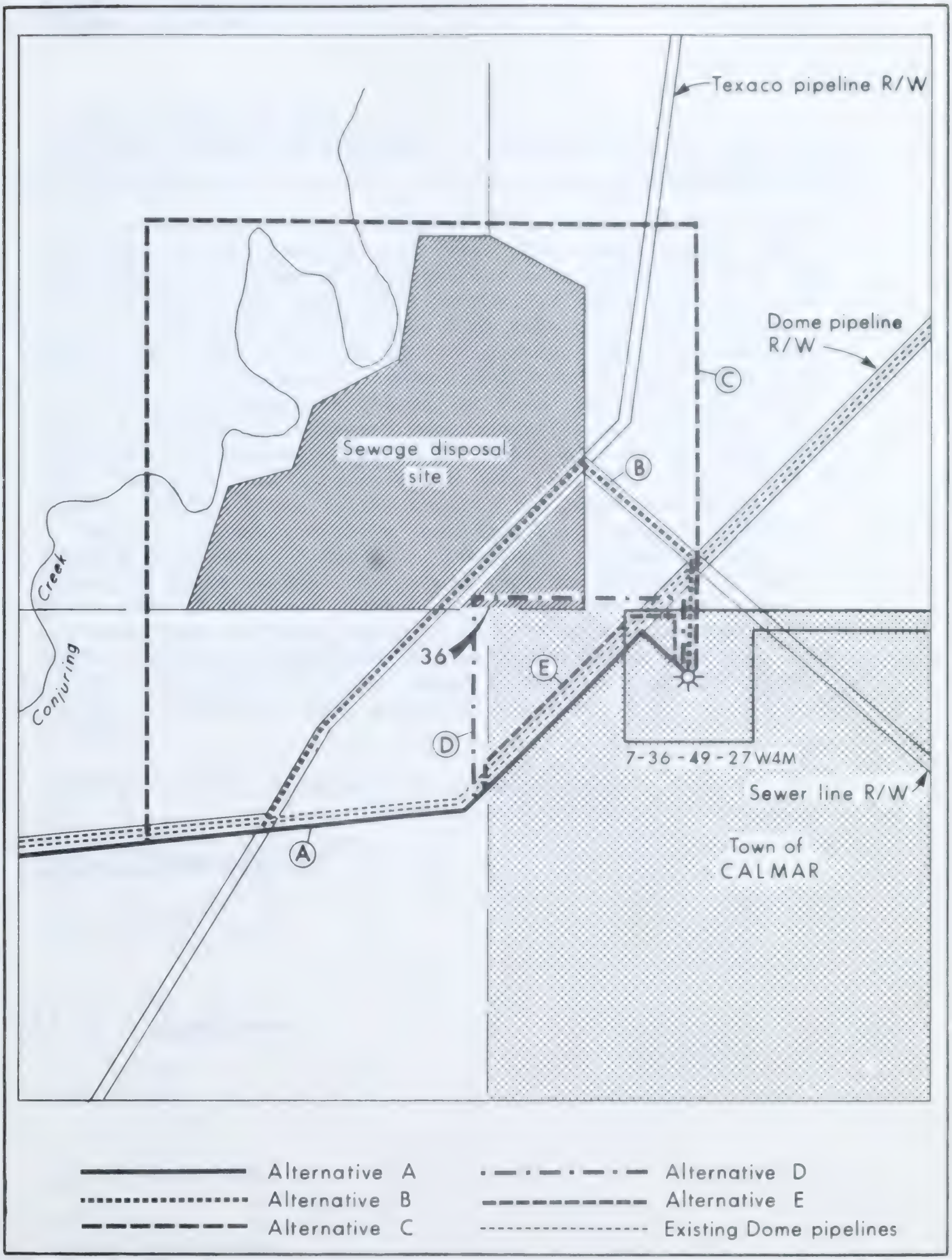


FIGURE 2 ALTERNATIVE PIPELINE ROUTES

ENERGY RESOURCES CONSERVATION BOARD
Calgary, Alberta

PASSBURG PETROLEUMS LTD.
SECONDARY NATURAL GAS PIPELINE
CALMAR AREA

Addendum to Decision 82-35
Application 820949

There appears to be some confusion as to which pipeline route the Board has approved in this case. For clarification, the Board has approved a route which runs from the wellhead of the 7 of 36 well to the Dome right of way, as shown for Route A in Figure 2. It departs from Route A at this point and extends across the right of way to the north side, where it intersects with Route E as shown on Figure 2. It then follows Route E in a southwesterly direction along the right of way to the west side of the western boundary of the quarter section where it recrosses the Dome pipeline to the south side of the right of way. The line then parallels the Dome line west to the 7 of 35 tie-in. As mentioned in the report, the Board sees little difference between the above described route and the complete Route E as shown on Figure 2. Therefore, if Passburg and Landstrom agree to any other route from the wellhead to the north side of the Dome right of way which runs between the approved route and that shown in Route E running straight north, the Board would specify that route in the pipeline permit. The permit will be issued as soon as possible after the Board receives a plan allowing the route to be specified in detail.

DATED at Calgary, Alberta, on 25 November 1982.

G.J. DeSorcy

G.J. DeSorcy
Vice Chairman

C.J. Goodman

C.J. Goodman
Board Member

E.J. Morin

E.J. Morin
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY ALBION PETROLEUM CORPORATION LTD.
FOR AN EXPERIMENTAL IN SITU OIL-SANDS SCHEME
IN THE BONNYVILLE AREA

Decision 82-36
Application 820244

1 INTRODUCTION

The Energy Resources Conservation Board received an application from Albion Petroleum Corporation Ltd., pursuant to the Oil and Gas Conservation Act, for approval for a 10-year term of an experimental oil-sands scheme in section 12, township 61, range 6, west of the 4th meridian. Due to nearness to the Town of Bonnyville and a perceived concern of local residents and landowners, a public hearing was called. The attached figure shows the locations of the proposed surface facilities and project area, the Town, and Jessie Lake, a body of water immediately south of the Town.

Albion proposes to recover bitumen from the Colony Sand of the Cold Lake - Upper Grand Rapids Oil Sand Deposit contained within Oil Sands Lease No. 0981060001 (previously P&NG Lease No. 22470).

The proposed scheme would involve the drilling and completion of 17 slant-hole wells and the completion of an existing oil-sand evaluation well to form an 18-well pattern, on 3.25-hectare (ha) spacing.

The facilities would be designed to recover 129 cubic metres per day (m^3/d) of crude bitumen by cyclic steam stimulation.

The proposed site is in Lsd 7-12-61-6 W4M. The steam-generation and battery complex would occupy approximately 7.4 ha, of which 5.75 ha would be leased from the Town of Bonnyville. The water supply for the project would be obtained from the Town of Bonnyville.

2 THE HEARING

The application was considered at a public hearing on 21 September 1982 in Bonnyville, Alberta, with G. J. DeSorcy, P.Eng.; C. J. Goodman, P.Eng.; and N. Strom, P.Eng., sitting.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Albion Petroleum Corporation Ltd. (Albion) W. A. McBean, P.Eng.	W. A. McBean, P.Eng. W. G. Roddie, P.Geol. B. Berci W. J. Rodgers, P.Geol.
Community Advisory Committee (CAC) D. Appleby	
W-32 Corporation Limited and Six-Vee Enterprises Limited (W-32/Six-Vee) P. J. Renaud	N. Runka
BP Exploration Canada Limited (BP) Dr. J. Duckett	
Her Majesty the Queen in the Right of Alberta J. Defir, P.Eng.	
Energy Resources Conservation Board staff D. A. Holgate R. G. Evans, P.Eng. H. O. Lillo, P.Eng. W. A. Mayer, C.E.T.	

3 ISSUES

The Board considers that the first issue it must address in dealing with this application is:

- The General Suitability of the Proposed Scheme.

If the Board is satisfied in this respect it will then consider the following more specific matters:

- o Technical and Safety Considerations
- o Environmental Considerations
- o Land-Use Conflicts.

4 GENERAL SUITABILITY OF SCHEME

4.1 Views of the Applicant

Albion submitted that 266 000 m^3 or 20 per cent of the original oil in place could be recovered by cyclic steam stimulation. The recovery factor of 20 per cent was derived by comparing the recovery estimates of other projects in the area, then taking into account the larger well spacing, lower bitumen viscosity, and lower bitumen density of the proposed scheme. Albion pointed out that some primary production had been extracted from the reservoir in the early 1950s, demonstrating that recovery from its reservoir should be easier than from other bitumen accumulations in the region.

It stressed, however, that primary recovery was not economically feasible and, in order to recover the resource, the experimental scheme was appropriate from a conservation viewpoint.

Albion acknowledged that there was a risk factor in any development of this nature and that it had weighed those risks. It believed that current problems respecting heavy-oil markets would be corrected in the near future and that the market value of oil would improve. When questioned respecting the financeability of the project, the applicant stated it would take about two years' experience to determine the economic viability of the project. Albion would abandon the scheme if it proved unprofitable.

One of Albion's experimental objectives would be to determine if a scheme could be compatibly operated near a town. If so, others may be able to conduct similar operations within the province. Another experimental aspect would be to test 3.25-ha well spacing rather than the traditionally smaller spacing units for this type of project.

Albion proposed to use a slant-hole drilling rig to minimize surface disturbance. Such a rig would drill straight holes, but they would be slanted directly from the surface location to an offset downhole location. This is contrasted to another form of directional drilling where the rig starts off with a vertical hole and then at an appropriate depth angles the hole directionally to the desired bottom location. Albion tentatively proposed to use at each well a screw-type pump jack that could also function as a service rig; but the company would evaluate other pumping systems before deciding.

Albion stated that its plan to fund a capital portion of the Town's water system would be an economic advantage to the Town. The Town would also receive municipal taxes and rental payments for the land to be used.

Albion indicated that if the population growth resulting from its project led to an abnormal load on facilities such as hospitals, it would consider additional funding for such institutions.

The applicant stated a belief that the scheme would not be deleterious to commercial business development, would remove only 7.4 ha of surface land for ten years, and would have a better visual appearance than some other existing commercial enterprises in the area. Albion also indicated that, during the construction and operation phases, local people would be employed as much as possible.

When questioned, the applicant agreed that it would accept a 5-year term of experimental status provided that the scheme would be allowed to be converted to commercial status for an additional five years.

4.2 Views of the Interveners

W-32/Six-Vee argued that essentially no benefits would accrue from the proposed project. It stated that the scheme would be detrimental to residential areas in the Town, would create a noise and safety problem, and would also be a potential pollution hazard.

W-32/Six-Vee expressed a concern that, on the expectation that the scheme would not be a great money-maker and could result in premature abandonment, the applicant may not have adequate financial resources to prevent an adverse impact upon the adjacent lake, the surrounding land, and the community as a whole. This could be especially serious if the scheme were economically unsuccessful.

The intervener also argued that Bonnyville is not the place for an experimental project and that such projects should be located away from residential areas.

The CAC expressed certain concerns, but did not take an overall position that the proposed project was unsuitable.

4.3 Views of the Board

In terms of general suitability, the Board agrees with Albion that essentially none of the bitumen or heavy oil could be recovered by primary production means. The project, if successful, would thus serve the interests of energy resource development and conservation. The Board regards the 20 per cent recovery factor estimated by the applicant to be speculative, recognizing the nature of the project and the very limited ability to make such estimates by analogy to similar schemes.

Respecting the ability to finance the project, the Board notes Albion's statement that it and prospective partners would proceed with the scheme only if they had sufficient financial resources to see it through. The

Board generally accepts this and, indeed, questions whether the usual sources of capital would finance the project unless they were properly satisfied respecting the overall competence and financial position of the proponents. The Board notes the concern expressed by certain interveners that, should the project be an economic failure, it might be abandoned in an unsatisfactory manner. The Board considers that existing controls via the Land Surface Conservation and Reclamation Act, including that of general as well as special security deposits, are adequate protection against any such unsatisfactory outcome.

Regarding the experimental objectives of the proposed project, the Board agrees that testing the viability of both the proposed recovery process in the particular portion of the oil-sand deposit identified, and the intended well spacing, would have experimental value. However, while the operation of the proposed recovery facilities may prove compatible with the Town, the Board regards that as a possibility, not an experimental objective. If the scheme was to proceed, the Board would grant it experimental status for a five-year period. It is common for the Board to extend the approved experimental term by five or more years to allow fulfillment of experimental objectives.

The Board anticipates that the Town of Bonnyville and surrounding region would receive certain economic benefits from the proposed project, such as jobs, the payment of taxes, and other expenditures by the scheme's proponents.

All things considered, the Board is satisfied that the proposed scheme is sufficiently suitable in general terms to receive approval, provided that the potential impact on the residents of Bonnyville would be acceptable. Specific impacts are therefore examined in detail later in this report.

5 TECHNICAL AND SAFETY CONSIDERATIONS

5.1 Views of the Applicant

The applicant stated that the slant-hole wells would have surface casing and would be completed with thermal cement and prestressed production casing. It claimed there would be little chance of casing failure, because, in the straight slant-holes, the casing would experience only linear expansion and contraction, which would be counteracted by prestressing.

The applicant proposed to locate the surface facilities, consisting of two well pads, steam generation equipment, treating and separating vessels, storage tanks for bitumen and water, and shop, warehouse, and office, within a 7.4-ha area.

Albion stated that the plant would be designed with great stress on safety and the prevention of upset conditions. Included would be an emergency

shut-down system comprised of an electronic device that would sense an upset condition or potential hazard and automatically shut down the plant or wells. The closed treating vessels and tankage would be continuously swept with a blanket of sweet natural gas to prevent vapour escaping to the atmosphere. Vapour entering this system would be burned with the natural gas as fuel for the steam generators.

Steam generation equipment would consist of a conventional oilfield package complete with automatic controls, alarms, and safety shut-down systems. The wellhead would be capable of handling the maximum operating pressures and temperatures anticipated.

5.2 Views of the Interveners

W-32/Six-Vee contended that the presence of high pressures and temperatures rendered the operation basically dangerous. The project would therefore pose special risks if future residential developments brought an urban population close to the proposed plant site.

Through cross examination, the CAC expressed concern that ice fog may be more prevalent than the applicant's studies predicted. This, coupled with tanker truck traffic, may present road hazards in the surrounding area. It was also concerned about truck routes and possible conflicts with school-bus and peak traffic in and around Bonnyville. Although it acknowledged that studies by the University of Alberta and the Provincial Government are inconclusive at present, the CAC speculated that the injection of high-pressure steam could cause land surface movements that might affect building foundations.

5.3 Views of the Board

The Board considers the well-completion and surface facilities to be technically acceptable for the type of scheme proposed. It believes there is a fair possibility for a casing separation to occur, due to the high temperature effects. Although such a failure would not ordinarily pose a safety hazard to surface installations, as a matter of subsurface environmental protection and sound engineering practice the Board would include, as a condition of any approval, a casing monitoring program to ensure early detection and repair of any such failures.

With respect to public safety, the Board is of the view that, provided all surface facilities are properly fenced to prevent uncontrolled entry and that the emergency shutdown and other control features proposed by the applicant are installed and properly maintained, the hazard to the public would be minimal. In the previously-stated circumstances, the Board believes that any release of produced fluids or other material to the atmosphere, land surface, or water would be in a controlled manner which, although a potential environmental problem, would not be particularly dangerous.

Notwithstanding the above view, because of the proximity of the proposed scheme to Bonnyville, extra care would be appropriate to ensure that all control facilities are operational at all times. In this regard, if the scheme was approved, the Board would condition its approval to require joint safety inspections by the project operator and the Board's staff during the construction and commissioning of facilities, and at periodic intervals during their operation.

6 ENVIRONMENTAL CONSIDERATIONS

6.1 Views of the Applicant

Albion indicated that it intended to be a good corporate citizen and to monitor and control emissions and put more than the usual amount of effort into making the proposed plant look aesthetically acceptable to the community. It proposed to collect all vented gas and operate in a manner such that environmental problems would not occur.

Water

Albion stated that it has an agreement with the Town for the required water supply. In response to questions, it said that the maximum amount required would be 77.2×10^3 m^3/year, which would be additional to the 3.2×10^6 m^3/year withdrawal from Moose Lake already approved by the Department of the Environment for the Town of Bonnyville. The water is pipelined from the lake to the Town's distribution system from where it would be piped to the scheme at Albion's expense. There would be sufficient water tankage at the scheme to cover a 3-day period of operation should there be an interruption or deficiency in the supply from the Town system. If an interruption or deficiency continued, Albion would be obliged to curtail or totally shut down its steam generators. The applicant indicated that alternative water sources had been considered and rejected: Jessie Lake, due to shallowness and quality; ground water, because of limited availability and the concerns of local users; and a separate pipeline from Moose Lake, due to less-favourable economics than that of the Town water system. The recycling of produced water as a means of reducing overall water requirements was rejected by Albion as it anticipated that the cost of water clean-up would be too high to be borne by an experimental scheme.

Albion proposed the Dina Formation for water disposal because of its large area, high porosity, and the absence of bitumen content. The applicant stated that there was a lack of information on any deep wells, but it would investigate other geological horizons if the Board directed it to do so. It contended that the injected waste water would not become part of the ground-water system, nor would it destroy any potable water supplies.

Air

The applicant said that there should be no odour from the closed atmospheric treating system. The sweet-gas blanket and the collected annulus gas would be burned. The very small amount of H_2S present, estimated by the applicant to be a maximum of approximately 10 m^3/d,

would be the only source of H_2S and consequently the only source of SO_2. According to the applicant, the H_2S would be flared in a manner that would not result in odours or other environmental impacts. Albion indicated that the only other potential pollutant to be released to the air would be nitrous oxide, which is odourless. It thus contended that the design of the plant should result in virtually no odours. In answer to questions, Albion agreed there could be small amounts of hydrocarbon odours from truck-loading or at the wellheads, but did not expect these to be detectable outside the plant gate. It said that if odour complaints were made, it would expeditiously investigate them and take any necessary action.

Noise

The applicant contended that noise from the plant would be minimal. It was Albion's submission that the night-time still-air noise level at a distance of 10 metres from the closest existing residential building would be less than 55 decibels (dBA). Albion also stated that it would conduct noise-level surveys and maintain 50 dBA at its scheme boundary.

Upon questioning, Albion said the main source of noise would be the blower fan on the generator, the steam generator, and the 14-m flare stack. The applicant indicated that the first two noises could be reduced by insulating the steam-generator building, and the third by an elaborate exhaust system.

Albion suggested that a commercial operation could be located next door without noise-related problems, and said that residential housing would be perceived to be incompatible only if it was constructed very close to the proposed plant.

Land

Albion indicated three potential routes for trucking the production: a first one north to the AEC line near LaCorey, a second through Bonnyville to Suncor's Fort Kent facilities, and a third and preferred route to Suncor's facilities via a route some distance south of the Town.

The applicant stated that the volume of sand expected to be produced with and separated from the oil is indeterminate, but that it could be used by the Town for road building.

Albion said it had an agreement with the Town that required the land to be restored to its present state or better when operations were completed. Albion also stated that well abandonment would be controlled by the Board.

6.2 Views of the Interveners

Through cross-examination of the applicant, the CAC made reference to various environmental matters. There was concern that Albion would be relying on an unproven annulus-gas gathering system to collect and incinerate H_2S gas. According to the CAC, other operators in the area are

experiencing problems with similar gathering systems, and if the system was inoperative, H_2S could be released. The matter of why the recycling of produced water was not being considered as an experimental objective was raised again because some other operators are using this technology. The CAC questioned Albion as to why the Dina Formation was being considered for the disposal of produced water rather than deeper formations such as the Cambrian or Granite Wash. There was also concern that the Town would be providing water to the project but that Albion would have its own sewage system rather than using the Town's.

W-32/Six-Vee also raised various environmental matters. In general there was concern that Albion had not thought through the project thoroughly enough, and that many potential upset conditions tolerable in a remote setting would not be acceptable within a town. There was uncertainty that an acceptable noise level could be properly designed for and that, in general, the noise from the plant would be unacceptable in a residential area. Odours from trucks driving through residential areas could also be unacceptable. It believed the plant would be unsightly: in particular, the flare stack and piles of produced sand.

6.3 Views of the Board

Water

The water supply arrangements with the Town of Bonnyville appear to be acceptable for this size of operation. Although the requirement for the project would be substantial, the Board assumes that since the Town has made an agreement with Albion, it could be met without impact on the Town's supply. Also, if future expansions to the scheme were to be made, the Board would require the recycling of produced water to be considered.

The Board is concerned about the limited reservoir evaluation conducted, especially regarding water disposal. Before the Board would issue any water disposal approval, Albion would be required to conduct appropriate tests to evaluate both the McMurray and deeper formations.

Air

The Board believes that, even with the special measures proposed by Albion, some odour would be emitted. Contrary to the applicant's statement, SO_2 and NO_x have a distinct odour and, in the Board's view, under certain atmospheric conditions these and hydrocarbon odours would be detectable outside the plant boundaries. Given the proximity of the Town, the odours could be held to acceptable levels only with exceptional care in the design and operation of the plant. If the project was approved, the Board would require special arrangements for the reporting of odour complaints and the taking of prompt action.

Noise

The Board would expect Albion to design for and maintain a maximum of a 50-dBA noise level at the project boundary. Reporting and action-on-complaint arrangements similar to those relating to odour would be required if it was to grant approval.

Land

The preferred route for truck transportation of the hydrocarbon product (the southern route) is considered acceptable by the Board. However, it does not have jurisdiction in this regard. Communication would be necessary between Albion, the Town, and the CAC to minimize problems.

The problem of handling and disposing of produced sand is not expected to be serious. The Board would require that produced sand be stored in a cement-lined pit prior to disposal. It is assumed that suitable arrangements for disposal can be worked out with local authorities.

The Board has no jurisdiction with respect to sanitary systems and would expect the Town of Bonnyville and Alberta Environment to deal with this matter.

General

The Board expects that, even though some minor modifications might be required once the plant was brought into operation, the standards set by Alberta Environment, coupled with reporting systems for noise and odours, should readily take care of any environmental concerns.

Having regard for all environmental matters the Board therefore concludes that the impact of the scheme would not be such as to result in denial of the application. However, if the project does proceed, the Board would expect the operator to maintain regular and close communication with the public, probably through the Town and the CAC.

7 LAND-USE CONFLICTS

7.1 Views of the Applicant

Albion said that its proposed 7.4-ha plant site and well pads would be located southwest of the present townsite but within Bonnyville corporate limits (see the attached figure). The proposed operation would be located on two adjacent parcels of land: a 5.7-ha strip of reclaimed sewage lagoon leased from the Town of Bonnyville, and a 1.7-ha parcel of farmland. Surface disturbance would be minimized through the use of central well pads and slant-hole drilling. By comparison, considerably more surface disturbance would be experienced with vertical wells.

Based on current building trends in Bonnyville, it was the applicant's opinion that any future development near the site would be commercial rather than residential. Most of the housing construction in the past few years has been in the east end of town, whereas the west end has already developed into a commercial strip. With growth of the town based on the petroleum industry, there will be a high demand for commercial land. Albion indicated that the plant may deter very close residential development but not commercial. Albion said it had had discussions with some of the local school boards and understood that the project would be compatible with a school if the buildings were not directly adjacent to the plant site.

Albion stated that, to assure safety and reduce the visual impact, a chain-link fence 2m high would be installed around the site, and a row of trees planted to the north and west. A cottoneaster hedge would also be planted, to the east.

The applicant explained that oil development had taken place in section 12-61-6 W4M since the early 1950s when the now-abandoned wells were on primary production. Agents for the Bonnyville Gas Company had discussed the potential for a thermal heavy-oil recovery project with the surface owners as early as 1978, long before the W-32 Corporation proposed developing this parcel as a residential area.

7.2 Views of the Interveners

W-32/Six-Vee stated that they acquired an interest in the section in 1979, not knowing that any petroleum or natural gas development was being considered. Because of its proximity to the lake, the intent was to develop the land for higher-priced homes.

The intervener stated that residential, rather than commercial, development was planned for the area around the proposed plant site, and that such development would provide a better balance from a planning perspective than that of residential development east of the current town development. There are some problems with providing services to the area in question but, although difficult, servicing is technically feasible.

When the large Esso project at Cold Lake did not proceed, the residential development schedule for the land was set back. W-32/Six-Vee claimed that if the economy improved and Esso's or some other major project proceeded, the land could be brought into residential subdivision within five years.

Accordingly, W-32/Six-Vee considered Albion's proposed plant to be incompatible with the planned housing development. The aesthetics for residential development would be spoiled by metal buildings, tanks, and the flare stack, and the trees would provide an effective barrier for only four months of the year. They suggested there was a potential safety

hazard, uncertainty about noise and odour, and also a potential for Jessie Lake to be polluted.

W-32 asked that, if the project were approved, the Board consider requiring a bond to be placed as a source of funds, in case the company later proved unable to pay for anything that might go wrong.

7.3 Views of the Board

The Board recognizes that if both the land development and the experimental scheme were to proceed simultaneously, some degree of conflict would occur. Further, the Board considers it generally inappropriate to operate thermal recovery schemes of the kind proposed within a residential area. A decision as to whether the Albion project should proceed thus depends, to some extent, on whether residential development in the area proposed for the project is likely to take place during the project's lifetime.

When the W-32 Corporation acquired an interest in the land and proposed to develop it, apparently its forecasts of population growth were predicated on the building of Esso's Cold Lake mega project. Esso's shelving of its project has drastically changed those forecasts. On the basis of the evidence received at the hearing, the Board believes it unlikely that any large-scale residential projects will proceed in Bonnyville in the next 5 to 10 years. Bonnyville will probably experience a modest population growth, however, and some new subdivisions may have to be developed. The Board is not in a position to judge where that growth would take place but is aware that other areas are available for development.

If large-scale residential development did take place, it is likely that the land adjacent to the proposed plant site would be required for such development. In the absence of such development, which is unlikely for 5 to 10 years, adequate land elsewhere in the Town could handle the expected modest growth. The Board recognizes that residential development, even on a modest scale, could take place on the subject lands if markets for residential or commercial property exist. The area currently has no zoning designation and the Board understands that, before either commercial or residential zoning of the land occurred, the Town of Bonnyville would consider the matter publicly at a zoning hearing. The Town would also have to zone the land appropriately if the applied-for industrial project were to proceed.

With respect to the duration of the proposed scheme, the Board noted previously that if the scheme proceeded, it would be prepared to grant experimental status for a 5-year term. However, on the basis of evidence provided, the Board expects that the operation may indeed last 10 to 15 years, or even longer. At the same time, the Board recognizes, as a practical matter, that the hydrocarbons underlying the proposed project lands must be recovered before residential development takes place.

8 CONCLUSIONS

To summarize the benefits of the proposed project, the Board believes that much bitumen could be recovered that in all probability would not be, later, owing to the gradual growth of urban areas onto the lands in question. Also, the project would provide employment, tax and land rental money to the Town, and provide business opportunities within Bonnyville.

On the negative side, the project would represent a potential hazard to the environment and in terms of public safety. With appropriate controls, these would not be such as to cause denial of the application unless residential developments existed within 200 - 300 m of the proposed project. This is not the case today, but approval of the project would deter residential development in this immediate area because of aesthetics and the potential for noise, odour, and safety hazard.

These benefits and disbenefits must be considered in the light of the likely timing and duration of the proposed project and possible residential developments in the area. The project may have a life of 10 to 15 years or longer. Residential development is not expected to encroach upon the site for some 5 to 10 years. The Board believes this provides a compromise approach as a way to handle the application, and would be prepared to approve it with a condition limiting the project to a maximum term of 10 years commencing January 1, 1983. The project would then be terminated although the Board would be prepared, prior to the lapsing of the approval and on application from the project operator, to review the situation and could extend the term of approval if it was satisfied, on the basis of evidence available, that such an extension would be in the public interest. The Board recognizes that if the Albion project proceeds, even with the 10-year term, there could be financial impacts on W-32/Vee-Six. The Board would expect this matter to be dealt with by compensation, if warranted, resulting either from negotiations or by direction from the appropriate agency.

The Board notes that the evidence at the hearing on which its conclusions respecting land-use conflicts are based did not include detailed Town planning documents. The Board questioned witnesses respecting such documents but received no indication they existed. Since the zoning of the land to accommodate the applied-for project would require Town Council approval, the Board assumes that the necessary zoning changes would be forthcoming only if such would not be in conflict with the Town's planning.

The Board notes that W-32/Six-Vee requested that a security deposit be required since the project may be unsuccessful and improperly abandoned. The Board has no jurisdiction to require such a deposit but the Minister of the Environment does under the Land Surface Conservation and

Reclamation Act and Regulations. The Board intends to make the Minister aware of the intervener's request.

9 DECISION

Having regard for its findings and its responsibilities under the Oil and Gas Conservation Act, the Board is prepared to grant the application of Albion Petroleum Corporation Ltd. subject to the usual terms and conditions and to the following special conditions.

1. During construction of the project facilities and drilling of the project wells, the Operator shall report the progress of construction and site development to the Board on a weekly basis.

2. The Operator shall store all produced sand and oily waste in a concrete lined pit and dispose of it in an environmentally safe manner satisfactory to the Board.

3. (1) The Operator shall take such steps and effect such measures as may be necessary in the completing and operation of wells to prevent production casing failures.

(2) The Operator shall, prior to September 1, 1983, submit to the Board for its approval, a monitoring program designed to ensure early detection of production casing failures.

4. (1) Prior to the commencement of construction and in no circumstances later than June 1, 1983 the Operator shall submit to the Board for its approval a plan for the method by which the Operator would advise of, report on, communicate with the public about, and act on complaints of odour, noise, truck traffic and other deleterous effects the plant may have on the population around the plantsite.

(2) The Operator shall submit Annual Reports to the Board detailing the results of subclause (1) commencing with the first report period from January 1, 1983 to January 1, 1984.

(3) The reports shall be submitted no later than 60 days after the end of the reporting period.

5. The Operator shall, prior to commencement of operations, fence the perimeter of the plantsite in order to control any unauthorized entry.

6. The Operator shall not vent, flare or waste any gaseous or liquid hydrocarbons except in cases of emergency, unless otherwise authorized in writing by the Board.

7. (1) The Operator shall, not later than July 1, 1983, submit to the Board spill contingency plans for the scheme in the detail specified in the Board's Interim Directive No. ID-OG-PL 75-1.

(2) If bitumen, salt water, or other liquid other than fresh water is spilled from any equipment or facility associated with the scheme, the Operator shall take immediate steps to contain and clean up the spill.

(3) Where a spill occurs from a facility described in subclause (2) and

(a) the liquid is not confined to the site of the facility from which the spill occurred, or

(b) the volume of liquid spilled is in excess of 2 cubic metres,

the Operator shall immediately report the size and location of the spill to the Board by the quickest and most effective means.

(4) When so directed by the Board, a report made pursuant to subclause (3) shall, within two weeks of the date of the spill, be confirmed in a written report to the Board and be supplemented with at least the following additional information:

(a) the time the spill occurred,

(b) a description of the circumstances leading to the spill,

(c) a discussion of the spill containment and recovery procedures,

(d) a discussion of steps to be taken to prevent similar spills in the future, and

(e) an outline of the proposed spill site rehabilitation program.

8. No subsurface disposal of any aqueous wastes from the project shall be proceeded with unless the Operator has

(a) conducted such further drilling and studies as may be necessary to determine the feasibility of using strata of Cambrian Age as a subsurface disposal zone,

(b) submitted a report to the Board with respect to the further drilling and studies, and

(c) obtained written authorization from the Board as to the manner and zone of subsurface disposal.

ISSUED at Calgary, Alberta, on 3 December, 1982.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

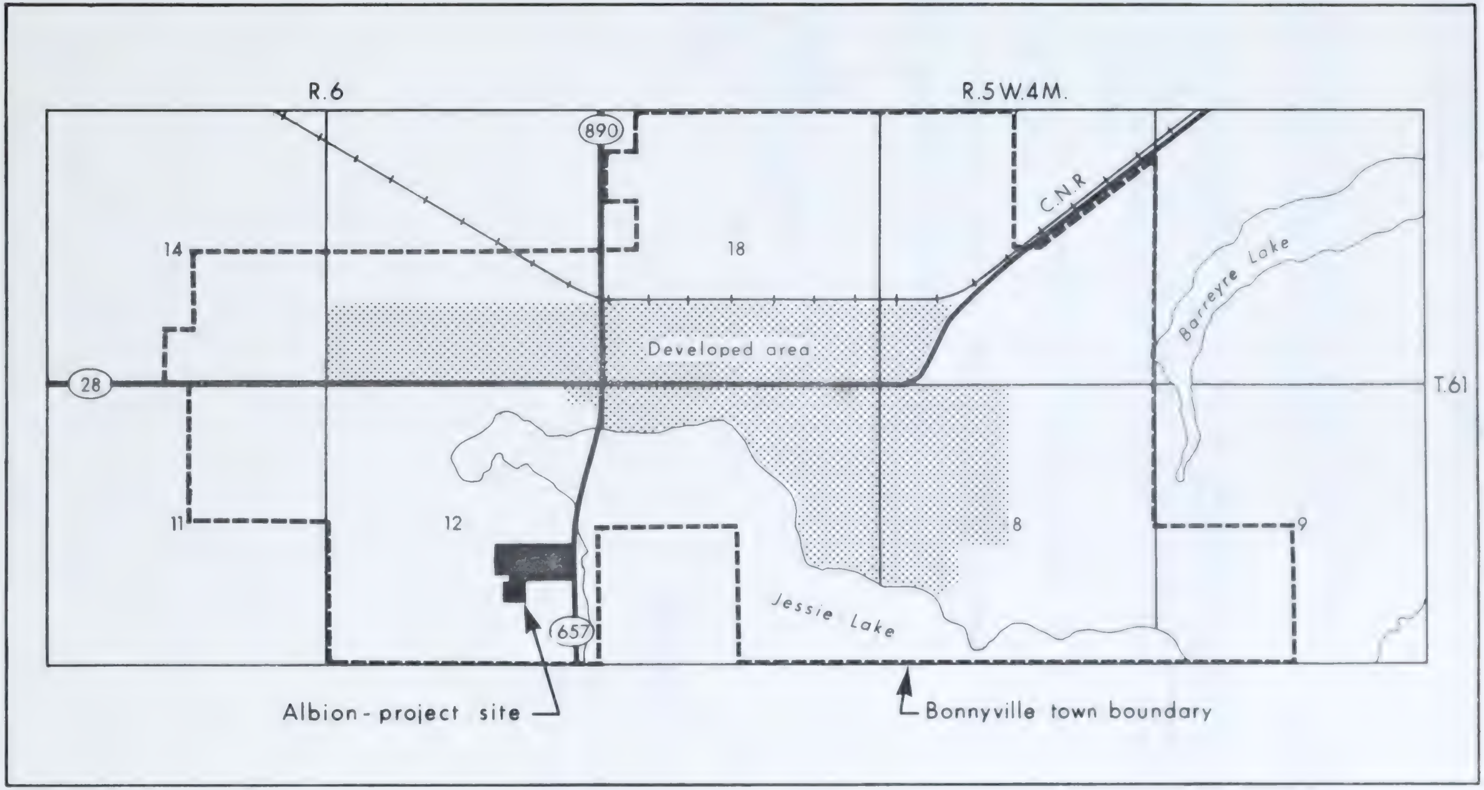
G. J. DeSorcy, P.Eng.
Vice Chairman

N Strom

N. Strom, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member



ALBION'S PROPOSED DEVELOPMENT WITHIN BONNYVILLE TOWN BOUNDARY

APPLICATION NO. 820244

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION FOR AN INDUSTRIAL DEVELOPMENT PERMIT TO MANUFACTURE AMMONIA AT KATHLEEN

Decision 82-37
Application 820229

The Board has reviewed the report of its Examiner, attached hereto, respecting Application 820229 for an industrial development permit authorizing the use of natural gas as raw material and fuel for production of anhydrous ammonia at a new plant to be constructed near Kathleen.

For purposes of its decision, the Board adopts the Examiner's recommendations.

DATED at Calgary, Alberta, this 7th day of December 1982.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

PEACE RIVER FERTILIZER INC.
INDUSTRIAL DEVELOPMENT PERMIT
TO MANUFACTURE AMMONIA

Examiner's Report E82-30
Application 820229

1 THE APPLICATION

Peace River Fertilizer Inc. applied, pursuant to section 30 of the Oil and Gas Conservation Act, for an industrial development permit allowing the annual use of up to 68 million cubic metres of natural gas for production of up to 78 000 tonnes of anhydrous ammonia per year in a new plant to be constructed near Kathleen. Approximately 20 per cent of the total gas requirement would be used as process fuel.

A 20-year permit term, commencing with plant start-up projected for May 1985, was requested.

2 THE HEARING

A public hearing of the application was held in McLennan, Alberta, on 19 August 1982, with N. Berkowitz, P.Eng., sitting.

The parties who appeared at the hearing are identified in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Peace River Fertilizer Inc. (Peace Fertilizer) W. R. Middagh, P.Eng. M. J. Mitchell, P.Eng.	W. R. Middagh, P.Eng. M. J. Mitchell, P.Eng.
Smoky River Regional Economic Development Board (SRREDB) R. Swetnam L. Meardi	R. Swetnam L. Meardi
High Prairie Regional Economic Development Board J. Craig	J. Craig
Residents and Property Owners of Kathleen A. Lemay	
Other Local Interveners R. Hill F. Lessard P. Laurin G. Audet D. Isert D. Cox	
Alberta Environment F. Witthoeft, P.Eng.	
Energy Resources Conservation Board staff K. Miller M. Mumby	

The Agricultural Development Corporation Committee of Smoky River Municipal District #130 filed a submission but did not appear at the hearing.

3 THE ISSUES

Having regard for the Board's responsibilities under section 30 of the Act, the Examiner considers the principal issues to be:

- the efficient use of natural gas;
- markets for the ammonia to be produced in the proposed project; and
- the impact of the proposed project on the Alberta economy and, more specifically, the Peace River region.

4 THE EFFICIENT USE OF NATURAL GAS

Peace Fertilizer proposes to use a conventional, energy-efficient process that would include feed gas desulphurization and steam-reforming, shift conversion, and conversion of the cleaned compressed synthesis gas to ammonia over a catalyst. Natural gas and purge gas from the ammonia synthesis loop would be used as fuel for feedstock reforming, and energy throughout the system would be recovered by heat exchangers. Approximately 6 megawatts of electrical energy, mostly for synthesis gas compression, would be required, and a net energy consumption of 30.5 GJ/tonne of ammonia, based on the lower heating value of natural gas, was expected.

Although 90 per cent of the equipment for the proposed plant would be acquired from existing or discontinued operations elsewhere, the applicant intends to refurbish and upgrade it to ensure performance at the projected high level of energy efficiency.

The Examiner notes that Peace Fertilizer's intent to use older modified equipment makes it unlikely that the project will represent latest state-of-the-art technology. He is, however, satisfied that the plant could and would be operated efficiently and without undue waste of energy or feedstock.

5 GAS REQUIREMENTS AND AVAILABILITY

At maximum ammonia production of 78 000 tonnes per year, Peace Fertilizer's annual gas consumption would be 68 million cubic metres. The applicant has discussed alternative gas supplies with Bralorne Resources Limited and others, and foresees no problems in obtaining its full requirement from shut-in reserves in the region.

The Examiner agrees that sufficient gas would be available for the proposed project over the requested permit term, but would recommend that Peace Fertilizer be required to advise the Board of satisfactory arrangements for the supply of gas before start of plant construction.

6 ECONOMIC VIABILITY

The applicant submitted that requirements for nitrogenous fertilizer markets in the Peace River region are growing, and that the fastest growth is being experienced in demand for anhydrous ammonia. Most of the regional market is currently served by distant production facilities which impose penalties by high transportation costs, and Peace Fertilizer's ammonia plant, with storage facilities, would remove such penalties.

A market analysis for the region projects substantial increases in fertilizer application rates, as well as in acreages under cultivation; and since consumption of anhydrous ammonia is now almost entirely governed by its availability, the applicant expected to capture all of the Peace River area market for this fertilizer.

Peace Fertilizer estimated the capital cost of the project at $50 000 000*, including $4 145 000 interest costs during construction. For the 20-year period beginning in 1984, total production revenues of $524 150 000, total feedstock and fuel costs of $194 789 000, and total operating costs of $118 200 000 were projected; and after allowances for municipal taxes ($8 000 000), provincial corporate income taxes ($17 000 000), and federal corporate income taxes ($53 000 000) a net income of some $133 000 000 was expected to accrue to shareholders. These estimates assume that essentially all annual production in the years 1985-2004 would be sold. Peace Fertilizer stated that the minimum plant output needed to carry all costs, including costs of capital, would be approximately 50 000 tonnes per year.

The Examiner agrees that higher fertilizer application rates and fertilizer demand in increasing acreages under cultivation in the Peace River region are likely to cause growing demand for fertilizer in the area. However, the Examiner notes that expanded production facilities are scheduled to come on stream in the Edmonton area in the mid-1980s, and that near-term fertilizer prices in Alberta are likely to reflect some excess of supply over demand. In view of this and the expected competition for available domestic markets until at least the late 1980s, Peace Fertilizer's estimate of its share of the Peace River regional market to the end of the 1980s may be overly optimistic. On the other hand, the Examiner recognizes the advantage of lower transportation costs and the consequent potential economic attractiveness of Peace Fertilizer's proposal over the long term.

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* Following the applicant's basis for calculating benefits and costs associated with the project, 1984 constant dollar values are used throughout this report.

7 IMPACT OF THE PROPOSED PROJECT ON ALBERTA

Peace Fertilizer estimated the total direct impact of the proposed project on Alberta to be the sum of capital spent in Alberta ($39 750 000) and net revenues generated in Alberta ($329 000 000), less capital raised in Alberta ($50 000 000) and revenue outflow from Alberta ($57 000 000). Assuming a x2 multiplier, the resultant net positive direct impact ($261 750 000) implies a total direct and indirect impact of $523 500 000 on the provincial economy over the 20-year permit term requested.

A similar calculation indicated the total (direct plus indirect) economic impact on the Peace River region to amount to some $291 000 000 over 20 years. However, Peace Fertilizer submitted that the dollar impact so calculated would grossly understate the value of the project to the region, and that a more realistic multiplier for calculating the regional impact would be 4.5. It noted in this connection that successful regional production of fertilizer would allow production of an additional 198 000 tonnes of ammonia per year by the year 2004. That, as well as future production of solid fertilizers, would attract heavy industry to the region; and the total direct and indirect employment attributable to fertilizer production could, by 2004, be as high as 500.

In the Examiner's view, Peace Fertilizer's estimates of direct and indirect impact of the proposed project on the Alberta economy are reasonable.

With respect to regional impact, he believes a multiplier between 2 and 3 is more appropriate than the applicant's 4.5; but even so, he agrees that the project would be of significant economic benefit to the Peace River region, both in dollar terms and in terms of new employment.

8 ENVIRONMENTAL AND SOCIAL IMPACTS

Peace Fertilizer stated that atmospheric emissions from the proposed plant would be normally limited to flue gas from the reformer furnace vent and carbon dioxide. If possible, the carbon dioxide would be sold for tertiary recovery purposes in nearby oil fields. The reformer vent stream would contain nitrogen oxides, carbon dioxide, oxygen, steam, and approximately 55 kilograms of ammonia per day. Abnormal emissions would occur for 8 to 16 hours during start-up of the plant, and would then be comprised of hydrogen, nitrogen, carbon dioxide, carbon monoxide, steam, and minor amounts of sulphur. Stack emissions would be monitored as required.

There would be no solid or liquid effluents from the plant site; but in any given year, some of the waste water must be expected to overflow from the holding lagoon into the surrounding watershed. The requirements of Alberta Environment would be met with respect to the quality of any such water overflow.

The use of air- rather than water-cooling would prevent significant ice-fog formation by the plant, and all compressor facilities would be designed to reduce noise.

The applicant stated that although ammonia could be classified as a hazardous material which, when vaporized, can be toxic and explosive, it presents little risk when handled safely. The layout of the plant would provide on-site containment of any major ammonia spill, and conform with Alberta Environment guidelines in this regard. Alberta Environment and the Board would also be furnished with full details respecting the applicant's planned maintenance and operating procedures, which would provide for early detection and prompt repair of ammonia leaks.

Peace Fertilizer estimated that the project would create 50 permanent on-site jobs, and that some 40 of these would be filled by local recruitment. In addition, some 20 off-site employment opportunities would be created, as well as temporary employment during busy loading seasons. Construction of the plant would require up to 100 workers.

The applicant estimated that the population in the area of the plant site would increase by between 30 and 40 people.

The SRREDB supported the proposed project on the grounds that it would enhance local employment opportunities, generate additional municipal tax revenues, and lower fertilizer costs to farmers in the area.

In a survey of 27 area residents who either own land or live within a 3-mile radius of the proposed plant, the SRREDB found that 54 per cent favoured the project, 21 per cent opposed it, and 25 per cent were undecided. However, the SRREDB stated that its results were only thought to indicate a need to clearly inform local residents about the possible side effects of the plant. The SRREDB was confident that Peace Fertilizer could be integrated into the community as a good corporate citizen.

The High Prairie Regional Economic Development Board also supported the application because of the benefits which the project would bring to the region, but qualified its support by noting its understanding that materials for the plant operation would be obtained locally.

The representative of the residents and property owners of Kathleen, Mrs. Lemay, expressed the group's concerns over possible future expansion of the plant, its impact on land values in the area, residue disposal, pollution levels under normal operating conditions and during times of temperature inversion, future soil acidity levels, and the effect of atmospheric pollution on dugout waters. Assurance was sought that the plant would not create long-term adverse effects on the community.

Other local interveners questioned the applicant on various siting and environmental aspects of the proposed plant, and suggested alternative sites.

The Agricultural Development Corporation Committee of Smoky River Municipal District #130 filed a written submission which supported the concept of a local anhydrous ammonia fertilizer plant, but did not appear at the hearing.

The Examiner is satisfied that compliance with all relevant requirements of Alberta Environment and the Board would make for a minimal and entirely acceptable environmental impact of the plant, and further believes that the project would not create serious social problems for local communities or individual residents.

9 FINDINGS AND RECOMMENDATIONS

The Examiner finds that Peace Fertilizer's proposal would use natural gas reasonably efficiently, and notes, in this regard, the applicant's commitment to hold energy requirements to no more than 30.5 GJ/tonne of ammonia production. The Examiner also finds that sufficient gas would be available from Alberta sources to meet the needs of the project over the requested 20-year permit term.

Some concern must be expressed over the possibility that Peace Fertilizer may not be able to penetrate the market as extensively as its net income calculations assume. However, even somewhat smaller penetration would provide the Peace River region with a secure local supply of anhydrous ammonia, and bring significant economic benefits to the area. The Examiner further finds that the project would not require any substantial new infrastructure for transportation, electric energy supply or community services, and notes the applicant's statement that no government assistance for the project would be required.

As well, the Examiner concludes that the project would have no serious adverse environmental or social impacts, and that residual concerns of local residents could be readily resolved by the applicant through provision of adequate information about the project to interested individuals and communities in the area.

The Examiner therefore recommends that the Board, with the approval of the Lieutenant Governor in Council, issue an industrial development permit to Peace River Fertilizer Inc., as applied for in Application 820229. The permit would be in the form shown in the attachment, and would be subject to the terms and conditions contained therein as well as to any conditions imposed by the Lieutenant Governor in Council.

DATED at Calgary, Alberta, this 6th day of December, 1982.

N. Berkowitz, P.Eng.

A/OR/IDP
82 11 15
PRF-6/mea

FORM OF PERMIT

IN THE MATTER of the Oil and Gas Conservation Act, being chapter 0-5 of the Revised Statutes of Alberta, 1980; and

IN THE MATTER of an industrial development permit to Peace River Fertilizer Inc. authorizing the use within Alberta of gas produced in Alberta for the production of anhydrous ammonia

INDUSTRIAL DEVELOPMENT PERMIT NO. PRF 82-6

WHEREAS Peace River Fertilizer Inc. has applied to the Energy Resources Conservation Board for an industrial development permit, pursuant to section 30 of the Oil and Gas Conservation Act, authorizing the use of gas produced in Alberta for the production of anhydrous ammonia in Alberta; and

WHEREAS the Board, upon inquiry into the application, is of the opinion that the granting of this industrial development permit for the use of gas as raw material and fuel for production of anhydrous ammonia is in the public interest, having regard to, among other considerations, the efficient use without waste of energy resources and the present and future availability of hydrocarbons in Alberta; and

WHEREAS the Lieutenant Governor in Council, by Order in Council, numbered O.C. and dated , has authorized the granting of the permit.

THEREFORE, the Energy Resources Conservation Board, pursuant to the provisions of section 30 of the Oil and Gas Conservation Act, being chapter 0-5 of the Revised Statutes of Alberta, 1980, hereby grants an industrial development permit to Peace River Fertilizer Inc. (hereinafter called "the Permittee") authorizing the use of gas as raw material and fuel for production of anhydrous ammonia, subject to the regulations and orders made pursuant to the said Act and to the terms and conditions prescribed in this permit as follows:

1. This permit is for the use by the Permittee of gas as raw material and fuel for production of approximately 78 000 tonnes per year of anhydrous ammonia, generally as described in the application dated February 19, 1982.

2. The plant facilities at which anhydrous ammonia will be produced shall be located in the northeast quarter of Section 23, Township 76, Range 19, West of the 5th Meridian.

3. Subject to compliance of the Permittee with the terms and conditions hereof, this permit shall be for a term commencing on the date hereof and ending on May 31, 2005.

4. The quantity of gas that may be used in the industrial operation referred to herein shall not exceed 68 million cubic metres per calendar year.

5. The quantities of gas for the purpose of this permit shall be on the basis of a gas free of water vapour and having a higher heating value of 37.4 megajoules per cubic metre.

6. All gas used in producing anhydrous ammonia pursuant to this permit shall be measured by or on behalf of the Permittee in a manner satisfactory to the Board, and the volumes of gas used as raw material and fuel and of anhydrous ammonia produced shall be separately reported to the Board in a manner satisfactory to the Board.

7. The Permittee shall obtain the approval of the Board of any major changes in design of the plant facilities.

8. (1) The Permittee shall satisfy the Board, prior to , that arrangements for the financing of its proposed project have been completed, unless upon application by the Permittee a later date is stipulated by the Board.

(2) The Permittee shall satisfy the Board, prior to , that construction of its proposed facilities has commenced and will continue in accordance with a schedule approved by the Board, unless upon application by the Permittee, a later date is stipulated by the Board.

(3) The Permittee shall satisfy the Board, prior to , that arrangements for the supply of the necessary gas volumes have been completed, unless, upon application by the Permittee, a later date is stipulated by the Board.

9. During construction of the proposed project, the Permittee shall inform the Board semi-annually of the progress of construction.

10. The Permittee shall operate the facilities in a manner that results in

(a) the maximum practically obtainable efficiency in the use of gas for the manufacture of anhydrous ammonia, and

(b) the maximum practical conservation of gas.

11. The Permittee shall not

(a) assign this permit, or

(b) release from his control the operation of the plant,

without consent in writing of the Board, which may, with the authorization of the Lieutenant Governor in Council, be given by the Board upon application therefor.

12. (1) Attached hereto as Appendix A and made part of this permit, is the Order of the Lieutenant Governor in Council authorizing the granting of this permit.

(2) This permit is subject to the terms and conditions, if any, prescribed by the Order of the Lieutenant Governor in Council set out in Appendix A.

13. Where it appears to the Board or the Lieutenant Governor in Council that the Permittee has contravened or failed to comply with any terms or conditions contained in this permit or any relevant statutes or regulations of Alberta,

(a) the Board shall review the permit and with the approval of the Lieutenant Governor in Council may cancel the said permit or take such other remedial measures as considered suitable by the Board and the Lieutenant Governor in Council in the circumstances, or

(b) the Lieutenant Governor in Council may amend, vary, add to or replace any terms or conditions contained in this permit.

14. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this day of

ENERGY RESOURCES CONSERVATION BOARD

N. Berkowitz
Vice Chairman

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

SHELL CANADA RESOURCES LIMITED
GULF CANADA RESOURCES INC.
GAS PLANT APPROVAL AMENDMENTS

GULF CANADA RESOURCES INC.
PIPELINE PERMITS

PINCHER CREEK AREA

Decision 82-38
Applications 810543,
810606, 810376, and 810377

1 THE APPLICATIONS AND HEARING

1.1 Background

Gulf Canada Resources Inc. (Gulf) and Shell Canada Resources Limited (Shell) applied to turn down Gulf's Pincher Creek gas plant and to pipe the gas to Shell's Waterton plant for processing. The Energy Resources Conservation Board (Board) held a prehearing meeting on 18 August 1982 to discuss the general procedures and issues for the hearing of the applications. At the meeting the Pincher Creek Industrial Pollution Committee indicated its intent to intervene and requested that the plants' adverse affect on the health of community members be considered as an issue at the hearing. On 3 September 1982 the Board issued a memorandum of decision regarding matters raised at the prehearing meeting. The Board indicated that, it would hold a hearing to consider the specific applications, and then a separate inquiry to consider other more general issues such as alleged health affects. This report documents the issues respecting the applications as raised at the hearing and the Board's decisions respecting them. The inquiry will be held in 1983 when certain relevant information and documentation is complete and following a preinquiry meeting.

1.2 Applications

Application 810543

Gulf applied for approval to shut down its Pincher Creek gas processing plant located in legal subdivision 6 of section 23, township 4, range 29, west of the 4th meridian, and to install a refrigeration unit to recover natural gas liquids. The Pincher Creek and Lookout Butte dry gas and natural gas liquids would then be delivered in separate pipelines to Shell's Waterton gas processing plant for further processing.

Application 810606

Shell applied to amend its gas-plant approval to allow for Pincher Creek and Lookout Butte gas to be processed at the Waterton plant, located in sections 17- and 20-4-30 W4M. This gas is currently being processed at Gulf's Pincher Creek plant. The maximum permitted raw gas inlet rate would not be increased, nor would the plant process be changed.

Applications 810376 and 810377

Gulf applied for permits to construct two pipelines from the Pincher Creek gas plant to the Waterton gas plant. The figure shows the routes of the pipelines.

Application 810376 is to construct approximately 14.2 kilometres (km) of 168 millimetre (mm) outside-diameter (OD) pipeline to transport sour natural gas with a maximum hydrogen sulphide (H_2S) content of 52 mol/kmol. Application No. 810377 is to construct approximately 14.2 km of 88.9-mm OD pipeline to transport sour natural gas liquids with a maximum H_2S content of 98.6 mol/kmol.

1.3 Hearing

V. Millard, G. J. DeSorcy, P.Eng., and V. E. Bohme, P.Eng., considered the applications at a public hearing held on 15 November 1982 in Pincher Creek, Alberta. Those who appeared at the hearing are listed in the following table:

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Gulf Canada Resources Inc. (Gulf) J. D. Anderson	C. I. Pratt, P.Eng. G. Campbell L. T. L. Callow V. Mumby
Shell Canada Resources Limited (Shell) D. O. Sabey, Q.C. A. P. G. Walker	A. F. Mathes, P.Eng. Dr. M. D. Winning, P.Eng.
Her Majesty the Queen in the Right of the Province of Alberta (Crown) A. R. Watson	

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations used in Report)	Witnesses
Oldman River Regional Planning Commission (Planning Commission) W. P. McIntyre	W. P. McIntyre M. L. Schurmann T. J. Nicholson
Municipal District of Pincher Creek No. 9 (MD 9) H. Hammond	H. Hammond
Town of Pincher Creek (Town) Dr. J. J. Teran	Dr. J. J. Teran
Pincher Creek Economic Development Committee (Development Committee) F. S. Wood	
J. Hedenstrom	
Energy Resources Conservation Board staff M. J. Bruni E. P. Moeller, C.E.T. H. W. Knox, P.Eng. Dr. H. F. Thimm	

The Environmental Law Centre submitted an intervention on behalf of the Pincher Creek Industrial Pollution Committee but did not appear to support it.

2 ISSUES

The Board considers the issues respecting the gas-plant applications to be:

- the appropriateness of the Pincher Creek gas-plant turndown (including consideration of alternative courses of action),
- processing of Pincher Creek and Lookout Butte gas at the Shell Waterton gas plant, and
- plant site abandonment and reclamation.

It considers the issues respecting the proposed pipeline permits to be:

- the need for the pipelines,
- the safety of the proposed pipelines, and
- land-use matters.

3 GAS PLANT APPLICATIONS

3.1 Turndown, Alternatives, and Processing at Waterton

Turndown

Gulf applied to amend its Pincher Creek plant approval in order to essentially shutdown the operation and process the remaining gas reserves at the Shell Waterton plant. Some facilities would remain to separate the sour gas and natural gas liquids to be transported to the Shell plant.

Alternatives

Gulf investigated two alternatives to that proposed. One was to modify the Pincher Creek plant to accommodate the declining inlet rates. Gulf decided against that alternative because the cost of the refitting, including a new sulphur plant, would be high. Additionally, it would take about two years to make the conversion, during which time production would be suspended. The sulphur recovery plant would be difficult to operate efficiently due to declining production rates and lower-quality acid gas, and the sulphur recovery attainable even with a new sulphur plant would be considerably less than at the Shell plant.

A second alternative would be to continue to operate the existing plant until it is uneconomic or unsafe to do so. Gulf stated that the Pincher Creek plant could safely operate only until about 1983 when the minimum sulphur recovery efficiency level of 94 per cent could probably no longer be met with the existing sulphur plant. The plant would then be shut down and the gas remaining in the fields would not be recovered. Gulf indicated that under its proposed scheme, the Pincher Creek and Lookout Butte fields might produce for a further 8 to 12 years, thus improving gas recovery substantially.

Processing at Waterton

Shell contended that its application to process the remaining gas from the Pincher Creek and Lookout Butte fields at the Waterton plant should be approved because recovery of those reserves would be maximized, fuel gas consumption minimized, and a source point of sulphur dioxide (SO_2) emissions eliminated. Also, sulphur recovery would be higher at the Waterton plant than at the existing Pincher Creek plant or even at

a refitted Pincher Creek plant. Shell stated that no modifications to its plant would be required other than a tie-in to Gulf's proposed pipeline. It said that the additional gas would not significantly alter the annual throughput of the plant nor would it extend the life of the plant. The incremental volumes of gas to be processed are so small (0.65×10^6 m^3/day) that the overall composition of the raw gas processed at the Waterton plant would not vary significantly. Shell stated that the design capacity of the Waterton plant (13.3×10^6 m^3/day) would not be exceeded and the existing incinerator and flare facilities would be adequate to handle the additional gas. However, Shell submitted that the proposed scheme of processing Lookout Butte and Pincher Creek gas at the Waterton plant would be at a maximum rate of 12.0×10^6 m^3/day, well below the design limit. Shell stated that by consolidating the plants, noise, odour, and emission of nitrogen oxides would be reduced. Daily SO_2 emissions would be increased by about 0.7 tonnes per day for about a 10-year period but cumulative emissions in the area would be reduced by some 10 000 tonnes over the remaining life of the project. This would occur because the gas from Pincher Creek and Lookout Butte would be processed at a minimum sulphur recovery efficiency level of 98.7 per cent at the Waterton plant compared to 94 per cent at the Pincher Creek plant. Shell said that the reduction in emissions would likely be greater than estimated because, for the past two years, its plant had operated at an efficiency as high as 99.1 per cent. Over the past two years, emissions of SO_2 have been approximately 50 per cent of the approved emission limit.

Gulf and Shell supported each others' applications. Other participants in the hearing did not question the proposed turndown of the Pincher Creek plant, nor the processing of the declining Pincher Creek and Lookout Butte gas reserves at the Waterton plant.

Having considered the evidence the Board is of the opinion that processing the remaining Pincher Creek and Lookout Butte gas at the Shell Waterton plant would result in:

(1) A slight increase in SO_2 emissions at the Shell Waterton plant but not enough to have any measurable impact on the surrounding area or its residents.

(2) A reduction of overall SO_2 emissions in the general area.

(3) An increase in the recovery of gas reserves and sulphur.

(4) A reduction in the amount of gas used as processing fuel.

(5) Lower capital and operating costs than those of other schemes by which the remaining gas in the Pincher Creek and Lookout Butte fields could be produced.

(6) No change in equipment or significant change in operations at the Shell Waterton plant.

Therefore, the Board is of the view that, subject to the acceptability of the pipelines required to transport the gas, the requested amendments to the Gulf and Shell gas-processing projects are in the public interest.

3.2 Plant Site Abandonment and Reclamation

Gulf indicated that, although it would be occupying the plant site for about eight to nine more years, reclamation work would begin immediately. Gulf stated it would first turn down the refining and sulphur recovery portion of the plant, with the initial reclamation of that portion beginning sometime in 1984 after the equipment was dismantled. Also, it stated it was conducting soil tests on the sulphur stockpile site and noted that reclamation would begin there after the remaining stockpile was remelted for market.

Gulf said that it was undertaking several studies to develop a final reclamation plan for the plant site. While it noted the original agricultural land-use for the plant area it stated that the final land-use was uncertain but would most likely be decided in co-operation with interested parties such as the MD 9 and the Planning Commission. Gulf stated it did not have any plans for alternative industry uses.

The Town, MD 9, and the Planning Commission supported the Gulf and Shell applications and together with the Development Committee stressed that Gulf should encourage industrial use because contamination of the site might make it impracticable to return the land to agriculture. MD 9 stated that it was interested in obtaining control of any roadways abandoned by Gulf and in particular a road and bridge crossing Yarrow Creek approximately 1.6 km south of the Gulf plant.

The Board agrees with the interveners' suggestions that the existing Pincher Creek plant infrastructure could be used for other industrial purposes.

Regarding reclamation, the Board notes that Gulf will continue to occupy the site for some years to come. Notwithstanding, portions of the existing plant will be abandoned and proper cleanup and reclamation measures will be necessary. Toward this objective, the Board would require Gulf to present bi-annual reports to the Board and Alberta Environment respecting the status of dismantling and disposal of the plant equipment, and the reclamation efforts and results, and to indicate any changes in existing or planned land use for the plant site.

4 PIPELINE PERMITS

4.1 Need

Gulf stated that, if the Shell and Gulf gas-plant applications were approved, the proposed pipelines would be needed to transport Pincher Creek and Lookout Butte gas and natural gas liquids to the Shell Waterton gas plant. It indicated a life of about 10 years for the facilities depending on the depletion rate of remaining recoverable reserves.

None of the interveners questioned the need for the proposed pipelines.

The Board concludes the pipelines would be necessary to transport Pincher Creek and Lookout Butte gas and liquids to the Shell Waterton gas plant, and that they should be approved provided safety-related considerations and land-surface impacts would be acceptable.

4.2 Safety

Gulf stated that its proposed pipelines would be designed, constructed, tested, and operated in accordance with the Canadian Standard Association codes CSA Standard Z183 Oil Pipeline Transportation Systems, and CSA Standard Z184 Gas Pipeline Systems, as well as the Pipeline Act and Regulations. Gulf indicated that it had included additional design features to ensure that the pipelines would be as safe as possible, so as to alleviate local residents' concerns. These features included for example, specifying "desulphurized-steel" pipe, provision in the design for future internal pipeline inspection surveys, and an additional high/low pressure sensing emergency shutdown (ESD) valve on each pipeline to reduce the potential H_2S release volume in case of a serious rupture of the lines. Gulf amended its application at the hearing to include these extra ESD valves approximately midway along the 14.2-km route. It stated that although the potential H_2S release volumes would be reduced by a factor of approximately 2, the pipelines would still be classified by ERCB ID 81-3[1] as level 2 facilities.

In response to questions about the safety of crossing other pipelines and the types of pipelines crossed, Gulf stated that the crossing standards outlined in the CSA standard codes it proposed to use would ensure safe crossings. It noted that three crossings would involve other sour gas or liquid pipelines.

Gulf stated it would update its existing Emergency Procedure and Contingency Plan for the area to include residents in the vicinity of the proposed lines.

Concerning the condition of its pipelines in the area Gulf stated that its existing system had experienced only one corrosion pinhole since operations commenced in 1956 and was generally in good condition. It said that with proper corrosion inhibition programs and regular established maintenance and operation procedures it was confident the proposed lines would be safe.

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1 Energy Resources Conservation Board, 1981. Minimum Distance Requirements Separating New Sour Gas Facilities From Residential And Other Developments. Interim Directive ID 81-3. Calgary, Alberta.

Gulf stated that incremental impacts to the area would be small because its proposed lines parallelled existing pipelines for most of the route.

During examination of the applicant, Ms. Hedenstrom noted that the proposed pipeline would cross several other pipelines and expressed concern about the safety of construction practices in crossing these pipelines. She also said that "the density of pipelines" in the area appeared to be high and that the Board should take this into consideration when dealing with the applications. She suggested that the Board should set standards with respect to the number of pipelines that would be permitted in a given area, particularly those transporting sour gas.

The Board is satisfied that the design standards used by Gulf for the proposed pipelines, including the desulphurized-steel pipe and its proposed corrosion-control program, are consistent with the purpose and location of the lines. It also concurs with Gulf's intent to install additional ESD valves to further reduce the potential H_2S release volumes in the unlikely event of a break. In arriving at these conclusions, the Board has had regard for the evidence of Gulf that its Pincher Creek gas-gathering system remains in safe operating condition after many years of sour gas operations.

With respect to the parallelling of existing lines as proposed by Gulf, the Board generally supports the concept of running pipelines in corridors with other pipelines where this is practical. It believes that the overall impacts to the public and the environment are usually reduced by placing pipelines in parallel in a single corridor, and considers such would be the case respecting the lines proposed by Gulf.

Respecting pipeline crossings, Gulf said that 12 crossings would be necessary. Three Gulf lines would be crossed; two carrying sour gas and condensate respectively from wells located northwest of the plant and the third carrying sweet fuel gas back to the well site facilities. Two Nova sweet gas transmission pipelines would be crossed by the proposed pipelines. One of these lines would be crossed in two locations. Three ICG Utilities rural distribution lines would be crossed as well as three Dome Petroleum Ltd. pipelines: a sour condensate line and two oil/ products pipelines.

The Board believes that the necessary pipeline crossings could be accomplished with minimal hazard. It would require, however, that special precautions be taken during the crossing of the pipelines carrying sour products, and to ensure this, would require that the crossings not take place unless the Board's field inspectors were on site and the pipelines have been properly located and hand exposed.

In considering the continued safety of the proposed lines after they had been installed, the Board notes that recent amendments have been made to the Pipeline Act. The amendments place greater responsibility on all contractors to search records and check the area where it is proposed to

build roads, pipelines, utilities, or telephone lines, or create other ground disturbances that might result in contacting a pipeline. The Board is also conducting an extensive publicity campaign through seminars, publications, and advertising to advise contractors of their responsibility to avoid damaging pipelines. These amendments and the publicity campaign would, in the Board's view, reduce the possibility of third-person damage occurring to the proposed lines after their installation.

The Board has considered the matter of "pipeline density" from several different viewpoints. One aspect relates to the number of pipelines in a given area or in other words, the degree of concentration. Of more importance, however, are the implications on the safety of people in the area and in that respect the Board believes that density can be viewed in terms of

(a) the nature of the pipelines
(high pressure, toxic materials, etc.)

(b) the number and type of pipeline crossings,

(c) the density of population near the pipeline,

(d) the degree of activity (primarily construction) in the area that could contribute third-party damage, and

(e) the incremental effect on safety of the proposed pipeline.

In reviewing the pipelines proposed by Gulf and the pipelines that are already in place in the area, the Board does not believe the density or concentration of pipelines in this area is extreme. It is, of course, higher than would apply in many rural areas, but on the other hand is lower than that found in other areas such as near Calgary or Edmonton.

The area curently has a mixture of high and low pressure pipelines as well as several sour gas pipelines and is therefore sensitive from this point of view. Additionally, as referred to previously, several pipeline crossings would be required but the Board does not consider this to represent a serious problem providing proper care is taken in the actual construction.

The proposed pipelines would be relatively isolated from residences in the area - only three residences would be within 0.5 kilometres of the proposed lines with fourteen others within 1.5 kilometres. Thus the overall population density is relative low. Although Ms. Hedenstrom referred to a likely high rate of growth in population, other participants in the hearing, including the representatives of the Town and the Planning Commission, suggested an exceptionally high rate of growth should not be expected. There would not appear, therefore, to be serious potential problems with respect to third-party damage as one would expect to find with pipelines located near expanding urban centres.

For the above stated reasons, the Board does not believe that the addition of the proposed pipelines would have a significant incremental impact on the safety of residents in the area. The Board recognizes that the area does indeed have a number of pipelines criss-crossing it, but does not believe that the density that would be created by the addition of the two proposed pipelines significantly increases the risks to nearby residents.

4.3 Land-Use Matters

In response to questions, Gulf stated it would salvage topsoil on all cultivated land by stripping the "A" soil horizon for the width of the pipeline trench. It proposed not to strip topsoil from the full width of the right of way, nor from pasture land. To minimize the concerns of MD 9, it stated it would use only "Canada No. 1 seed" and provide the MD 9 with "certificates of analysis" detailing the type and amount of any noxious weed seeds that may be present with the grass seed.

The Board frequently hears evidence respecting the advantages and disadvantages of the various methods of soil reclamation available to an operator. It notes Gulf's plans to strip soil from cultivated lands but not from pasture. The Board accepts this as a general approach but believes that exceptions should be made upon request by landowners.

The Planning Commission raised a concern that the minimum spacing requirements for sour gas facilities established in ID 81-3 and the Provincial Subdivision Regulation, Schedule 6, AR 138/179 are not sufficient to prevent development near sour gas facilities. It suggested that other sections of the the Planning Act take precedence. For example, section 78 requires a municipal development officer "to issue a development permit for any parcel containing over 80 acres upon an application to construct or locate a second dwelling unit on the parcel". Also, section 86 allows the Land Titles office to accept for registration without subdivision approval a part of a parcel "described ... by reference to a plan of subdivision". The Planning Commission stated that this can result in dwellings or other buildings being constructed after a pipeline is in place and within the separation distance provided for in ID 81-3. It recommended that minimum-spacing clauses be included in future industry easement agreements and that the registering of separate property caveats indicating sour gas facilities be investigated.

During questioning, the Planning Commission stated that with respect to the specific applications before the Board, it did not expect many developments in the immediate vicinity of the proposed pipelines.

The Board appreciates the Planning Commission's concerns regarding the effect of ID 81-3 and the Subdivision Regulation on resident-safety and will bring the matter to the attention of the Alberta Department of Municipal Affairs. The Board does not, however, consider the matter to bear upon the decision regarding the subject applications.

5 DECISION

The Board concludes that there would be economic and environmental benefits in turning down the Pincher Creek Gas plant and processing the remaining reserves at the Shell Waterton Plant, and is prepared to amend the Gulf gas-plant approval. Subject to receipt of the Minister of the Environment's required approval with respect to environmental matters, the Board will issue the amendment with the following special condition:

> Gulf shall submit to the Board and Alberta Environment, bi-annually, a report on the status of dismantling and disposal of plant equipment, and details of reclamation results to date, including any changes in land use for the plant site.

For the reasons detailed in section 3 of this report, the Board is also prepared to amend Shell's gas-plant approval, subject to receipt of the required approval of the Minister of the Environment.

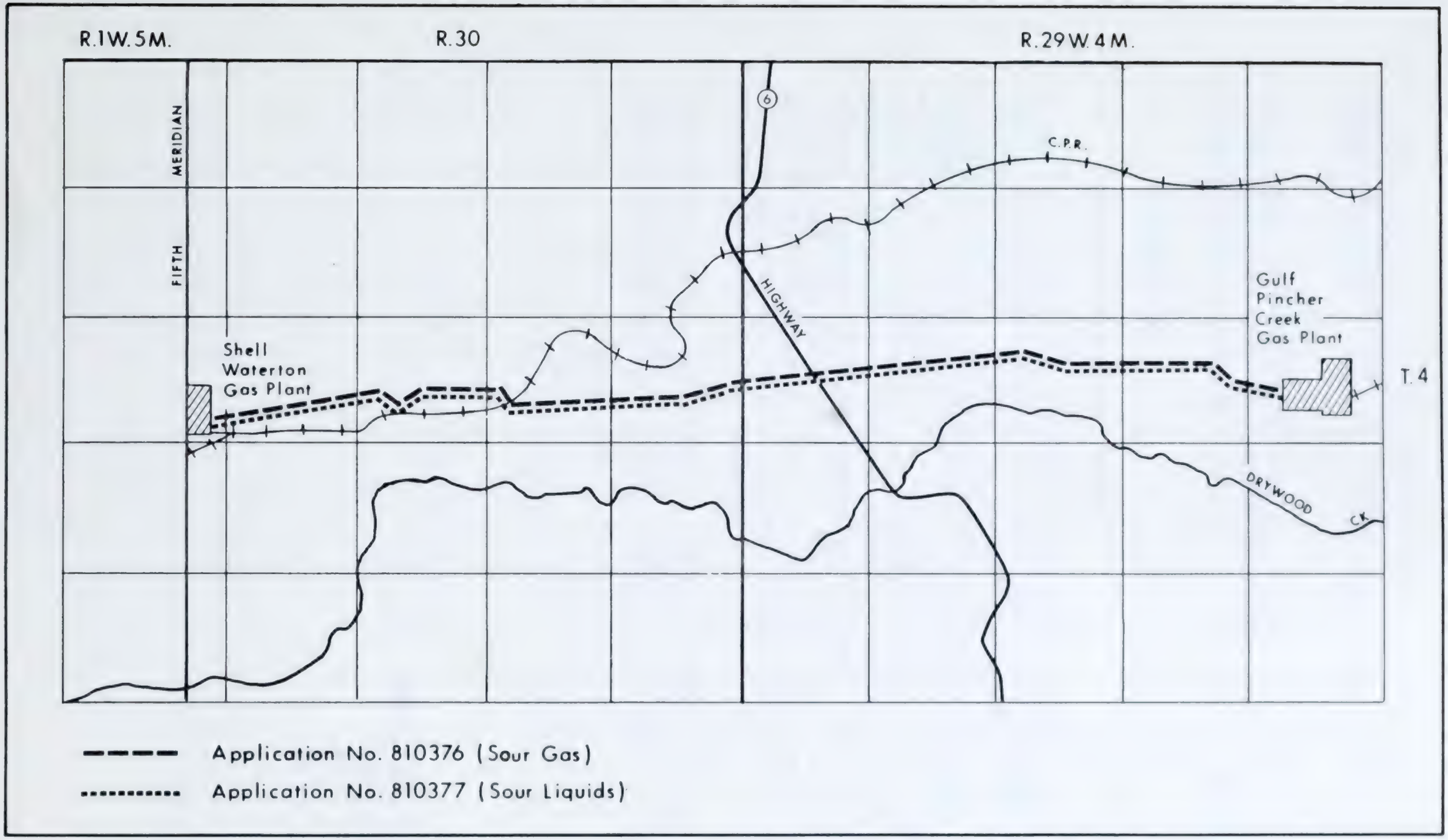
Concerning the Gulf pipeline applications, the Board concludes that the pipelines are needed and that the safety and land-use considerations are acceptable. It is prepared to issue the necessary pipeline construction permits subject to receiving the particulars of the Gulf amendment to include an additional ESD valve on each line midway along the route. The approval of the Minister of the Environment with respect to environmental matters will also be required. The following condition will be attached to the pipeline permits:

> Crossing of existing sour gas or liquid pipelines shall not commence unless an ERCB field inspector is present and the existing lines to be crossed have been located and hand exposed.

ISSUED at Calgary, Alberta, on 31 December 1982.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman



PROPOSED PIPELINES – PINCHER CREEK AREA

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA CANADA

ENERGY RESOURCES CONSERVATION BOARD
Calgary, Alberta

AMOCO CANADA PETROLEUM COMPANY LTD.
APPROVAL OF A SOLUTION GAS PROCESSING PLANT — Decision 82-39
ST. ALBERT AREA — Application 820308

1 INTRODUCTION

1.1 The Application and Hearing

Amoco Canada Petroleum Company Ltd. applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval of a scheme for the processing of sour solution gas gathered from three batteries in the St. Albert-Big Lake and Morinville fields. The proposed plant site would be located at an existing battery site in lsd 14-36-53-26 W4M (St. Albert site) some 4.5 kilometres (km) west of the City of St. Albert. The location of the proposed plant, existing batteries, the City, and other relevant landmarks are shown on Figure 1. The plant would be designed to process a maximum of 56.6 thousand cubic metres per day (10^3 m^3/d) of solution gas from which 49.2 x 10^3 m^3 of sales gas and 25.1 m^3 of liquified petroleum gases (LPG) mix would be recovered. A maximum of 0.734 tonnes per day (t/d) of sulphur dioxide (SO_2) would be flared through a stack 30 metres in height.

The application was considered at a public hearing on 6 and 7 October 1982 in Edmonton, Alberta with G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and E. R. Brushett, P.Eng. (Acting Board Member), sitting.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Amoco Canada Petroleum Company Ltd. (Amoco) G. G. Baugh	T. D. Strashok, P.Eng. R. J. Dreveny, P.Eng. R. L. Findlay
Silver Chief Community Gas Plant Committee (Silver Chief Group) D. Evans	C. Linttell C. Crozier
Genstar Land Development (Genstar) G. L. Stebner, P.Eng.	G. L. Stebner, P.Eng.
Municipal District of Sturgeon No. 90 (M.D. 90) C. Crozier	
Helenslea Acres W. J. Shymko	W. J. Shymko
Her Majesty the Queen in Right of Alberta (The Crown) S. L. Dobko, P.Eng.	
Energy Resources Conservation Board D. A. Holgate E. P. Moeller, C.E.T. P. K. Tse, C.E.T. S. L. Wolf, C.E.T.	

F. Bokenfohr, R. L. Brunelle, A. J. McDonald, D. J. McDonald, F. McDonald, K. Richardson, T. Victoor, and R. Nobis filed interventions but did not appear at the hearing.

2 INTERVENTIONS

The Silver Chief Group, made up primarily of nearby residents and landowners, was the principal intervener. Its submission dealt with concerns about emissions from the plant, safety, environmental matters, aesthetics, and the lack of information made available to them by Amoco.

The Silver Chief Group contended that it was Amoco's responsibility to make local residents aware of the entire project prior to, rather than during the hearing. The approximate location of the Silver Chief residential area is shown on Figure 1.

Helenslea Acres representing another group of residents appeared at the hearing to support the Silver Chief Group. The approximate location of Helenslea Acres is shown on Figure 1.

The Crown appeared for cross-examination only.

3 PRELIMINARY MATTERS

At the opening of the hearing, the Silver Chief Group requested that the hearing be adjourned because it considered the application too incomplete for Amoco to speak to its questions and concerns. The Silver Chief Group contended that the following matters needed to be addressed by the applicant for the application to be complete.

- an environmental impact assessment
- an air quality study of the Sturgeon General Hospital area
- an educational program for concerned residents
- consideration of alternative methods of sulphur recovery
- a discussion of the future of the plant including any plans to expand it.

In addition, the group said that it needed more time to gather other opinions and research documents on incinerator stack and sulphate emissions. Amoco opposed the request for adjournment and stated that it could respond to essentially all of the items mentioned by the interveners.

The Board denied the request for adjournment on the basis that adequate time had been provided to the interveners since an adjournment of almost four weeks had already been granted and that most of the items raised could be dealt with at the hearing.

4 ISSUES

The Board considers the issues regarding the application to be:

- conservation benefits

- location and impact of the proposed plant

4.1 Conservation Benefits

4.1.1 Views of the Applicant

Amoco stated that a gas processing plant was needed to process sour solution gas currently being flared at three oil batteries in the St. Albert-Big Lake and Morinville fields. However, the applicant stated that it did not as yet have final agreement to process gas from the Big Lake battery because the economics of gathering the gas are marginal, nor did it have a contract to sell any of the conserved gas at present. The Big Lake gas accounts for about 9.43×10^3 m^3/d or some 17 per cent of the proposed plant inlet volume.

4.1.2 Views of the Interveners

None of the interveners opposed the position that the gas should be conserved, but they expressed concern about environmental matters and the potential for expansion of the St. Albert-Big Lake Field.

4.1.3 Views of the Board

The Board agrees that it is desirable to conserve the gas currently being flared at the three battery locations and that a gas processing facility is required to accomplish this. However, the Board believes that conservation of the gas through the construction and operation of a gas processing plant at any location in this area should not proceed unless it can be satisfied that there are minimal negative impacts.

4.2 Location and Impact of the Proposed Plant

4.2.1 Views of the Applicant

With respect to the question of recovering sulphur, Amoco stated that it would cost $800 000 to construct a sulphur recovery facility which would cost about $80 000 per year to operate. At current and projected sulphur prices, Amoco estimated that if sulphur recovery facilities were installed it would incur a deficit of about $940 000 over the projected 15-year life of the plant. Rather than recover the sulphur, the applicant proposed that all hydrogen sulphide (H_2S) removed from the gas be burned and converted to SO_2 at the top of a 30-metre flare stack.

Amoco submitted that it had carried out dispersion calculations which had demonstrated that ground level concentrations of SO_2 would not exceed ambient air quality standards. The calculations indicated that a maximum concentration of 0.10 ppm would occur at a distance of 300 metres from the battery. This was compared to an allowable one hour maximum of 0.17 ppm. Amoco stated that the proposed plant would emit about 0.3 t/d of sulphur into the atmosphere if the gas were to be processed from all three batteries and compared this to 67.1 t/d of sulphur which it claimed is emitted from the City of Edmonton.

In discussing the plant, Amoco said that it would be equipped with a system for automatic shutdown of the plant and diversion of the solution gas to flare in the event of serious problems. Automatic igniters would be installed on both the acid gas flare stack and the emergency stack. Further, automatic flare stack igniter systems would be installed with the other operators consent on the Morinville and Big Lake battery sites. Amoco further offered to install a thermocouple at the top of the acid gas flare stack so that if the flare were to go out the gas would be routed to a second flare. This would minimize the chance of emitting any unburned H_2S to the atmosphere. Surface water would be controlled so as to ensure proper disposal of possible contaminated water runoff from the plant site. While the plant would not be manned 24 hours a day, an operator would check the plant regularly. Amoco gave assurances that the operator would live in St. Albert or Edmonton. With respect to other safety matters, Amoco stated that liquid petroleum gas (LPG) mixes and which are mostly propane and butane would be the only hazardous material transported from its plant. The LPG mix would be trucked along the shortest route and the vehicle would not be permitted on the road during school hours.

Amoco said that a new vapour recovery system would be installed on the old storage tanks at the St. Albert battery to minimize odours. Amoco claimed that it would be able to react within an hour to any complaints of odour or plant problems.

The applicant stated that it did not anticipate any expansion of the plant and that its only function would be to process solution gas from the St. Albert-Big Lake and Morinville fields. It contended that all other gas being produced from the area was sweet and committed to other plants.

Amoco said that it considered a number of locations for the proposed plant but preferred the St. Albert battery site because it is central to the gas to be gathered, and the land is flat and without trees which aids in dispersion of flared sulphur dioxide. The battery would be the

largest raw gas supplier to the proposed plant (53 per cent of the total plant inlet). Amoco further stated that if the St. Albert battery was used as a plant site, four small buildings would be added to house an electrically driven compressor, automatic equipment to operate and shutdown the plant, and a refrigeration system to remove natural gas liquids.

Amoco did not favour processing the gas at the plant operated by Norcen Energy Resources Ltd. (see Figure 1). It stated that the plant has no facilities to handle sour gas and is located in a low lying area close to a residential development. Therefore, the view was expressed that it was not suitable for installation of gas sweetening facilities. Amoco also emphasized the risk of transporting sour gas through a pipeline to the Norcen plant.

Another plant considered was the ICG Acheson plant located south of the St. Albert battery (see Figure 1). While this is a sour gas plant Amoco contended that it is currently operating at full capacity. Again Amoco discussed the disadvantages of transporting sour gas by pipeline to this plant and emphasized the cost for compression facilities and pipelines which in this instance was estimated to be $1.47 million.

Other potential sites having neither a production battery nor a processing plant were also considered but according to Amoco were ruled out because they would have been closer to the Sturgeon River, the City of St. Albert, or so far west as to render gas gathering uneconomic.

The Morinville and Big Lake battery locations were also considered. Amoco did not propose to construct the gas plant at either of the sites partly because other operators owned them. The view was expressed that economics would be seriously affected through transportation of the larger amounts of gas from the St. Albert site to either the Morinville or Big Lake site. Other reasons given for not choosing the Big Lake battery site were; the area is heavily treed, it is located on a flood plain, and is closer to Edmonton.

In response to the interveners' submissions Amoco stated that concerns about odour, aesthetics, and emissions would not go unheeded. As a result it made a commitment to monitor SO_2 and H_2S ground level concentrations locally and undertake a baseline study in the St. Albert area before the proposed plant went on stream. Amoco said that this would help to determine the source of complaints regarding H_2S or SO_2 odours. It further stated that it would make the results of the baseline study available to the Board, Alberta Environment, and the public. The applicant further undertook to increase its contact with the community to

alleviate concerns about its oil and gas activity in the area and to consult with the community during its planning. Amoco said that it would educate nearby residents about the hazards and effects of H_2S and SO_2. Baseline studies would also be undertaken on noise and if noise complaints resulted from the operation of the plant Amoco would find the source and do whatever necessary to remedy the problem. Finally the applicant assured the interveners that the plant would be planned and landscaped to be aesthetically pleasing.

4.2.2 Views of the Interveners

The Silver Chief Group said that it wanted the sulphur compounds contained in the gas recovered or, at least not emitted to the atmosphere. Also, it wanted the gas processed elsewhere than at the St. Albert battery. Although the Silver Chief Group wanted more information about all sites discussed by Amoco, it contended that the plant should be built at the Morinville site because fewer residents lived near it and there would be less impact from the plant. It was concerned that the plant emissions could cause serious environmental damage and could adversely affect human health.

The Silver Chief group contended that the applicant should bear the cost of installing sulphur recovery facilities rather than causing local residents to suffer ill effects from flaring. It submitted that the proposed plant would de-value property in the area because of the odours from it, and expressed concern that it could be expanded to a much larger facility. In addition, the Silver Chief Group stated that the proposed plant location would be within a Wildlife and Recreation zone and that the location would not be compatible with such a zone.

Mr. Crozier of M.D. 90, appeared on behalf of the Silver Chief Group, stated that M.D. 90 had some concerns about the plant and it would require a change to land use zoning. The M.D. 90 had scheduled a hearing to be held 26 October 1982 to consider the matter.

Genstar stated that as a developer, it held about 485 hectares of land in the northwest portion of the City of St. Albert and did not wish to see the proposed plant located at the Morinville site as proposed by the Silver Chief Group. With respect to the proposed site, it was concerned that the plant could have a negative impact on its plans for development. Genstar pointed out that any land use incompatible with current use would be detrimental to the community life style. It expressed a concern that because the plant would be upwind from its land, any odours emitted from the plant could have a very negative influence on its residential development. Concerns were expressed respecting heavy truck traffic which might result from operation of the plant.

Helenslea Acres generally agreed with the concerns expressed by the Silver Chief Group. It opposed any location of the plant near Helenslea Acres than that proposed by Amoco.

4.2.3 Views of the Board

In judging the acceptability of the proposed plant site, the Board believes it must have regard for:

- emissions expected from the proposed plant
- proposed safety features
- possibility of the proposed plant being expanded
- feasibility of processing at an alternative plant site
- aesthetics and other relevant matters.

EMISSIONS

The Board notes that there have been SO_2 emissions resulting from flaring of the unconserved gas at the three production batteries serving the Morinville and St. Albert-Big Lake fields since production began more than 20 years ago. Centralization of the emissions and flaring at the greater height proposed by Amoco would likely reduce ambient concentrations in general and in any case would ensure compliance with Alberta's ambient air quality standards.

Since oil and gas production is declining through depletion of the pools, the Board agrees with evidence presented that emissions will decline over the projected life of the plant. In this regard the board notes that the Big Lake battery which produces gas having the highest H_2S content is declining in production more rapidly than are the other batteries.

The Board, therefore, is of the view that the environmental damage, impacts on health and other unacceptable situations feared by the Silver Chief Group should not occur. In fact the Board believes that a properly operated processing plant and improved gas gathering facilities, as proposed, would likely result in an improvement over existing operations and in particular fewer odour occurrences in the area.

With respect to recovery of the very small amount of sulphur available at the plant, the Board believes that current technology does not provide a reliable or economic process for such recovery. Therefore, having regard for the expected decline in SO_2 emissions, the environmental safeguards proposed, and the technical and economic problems associated with sulphur recovery, the Board does not believe such a requirement to be warranted.

SAFETY

The Board shares the concern of the Silver Chief Group that the proposed plant must be operated safely. As well, transportation of certain liquid hydrocarbon products from the plant must not present an abnormal hazard to residents of the area.

The Board notes the following evidence presented by Amoco.

(a) the plant would be equipped for automatic shutdown in the event of problems,

(b) a shutdown would result in an alarm to the plant operator, not only at the plant but, since the plant would not be manned 24 hours per day, at the operator's residence,

(c) flares would be equipped with automatic igniters and thermocouples,

(d) provision would be made for diversion of the gas to a second flare to further ensure no venting of unburned gas,

(e) trucking of hydrocarbons from the plant would avoid critical periods such as when school buses are on the road.

With these major commitments as well as other safety features, the Board is satisfied with respect to the safety of the proposed plant provided Amoco ensures that the plant operator's residence is no more than 30 minutes drive from the proposed facility. If the plant goes ahead, the Board will require that Amoco inform the Board's Edmonton office of the proximity of staff residents to the facility. If operations of the plant showed that upsets were occurring frequently, or could not be responded to in an adequate fashion, the Board would consider the matter further and might order a change in the mode of operation.

PLANT EXPANSION

The Board does not believe it is likely that the proposed plant, if approved, would be enlarged to process further gas. The production from the fields the plant proposes to serve is declining. Other established gas reserves in the area generally do not contain H_2S and are being produced or are committed to other plants in the area.

Further, any proposed enlargement to the plant would be the subject of another application to the Board since any Board approval would limit the gas and sulphur inlet rate to the plant as part of the conditions of

operation. If an expansion was proposed the Board would, in conjunction with its review of the application, again consider the question of sulphur recovery.

LOCATION OF PROCESSING FACILITY

While Amoco applied for approval of only one site, being the St. Albert site, the Board recognizes that others may have merit having regard for the related transportation of the gas and general impact on nearby residences.

The Board believes that neither of the two existing plants in the area are suitable to process the gas. The Norcen plant is located near the City of St. Albert and the City of Edmonton. It is currently not equipped to process sour gas. Fourteen km of sour gas pipeline would have to be built north and east past the Silver Chief development and around St. Albert to the plant. The ICG plant, while a sour gas plant, has insufficient remaining capacity to handle this gas. Further, an 11 km sour gas pipeline would be required. The costs associated with pipeline and compressor construction and operation would render the project uneconomic. Further the presence of a sour gas pipeline on developed and developable land along the route could impose constraints on housing development.

Nearby locations other than the existing battery sites also present similar problems respecting the locating of sour gas pipelines. Further, a completely new site would result in an additional surface disturbance with no material reduction in facilities at the remaining three batteries.

For the above reasons and because the Board accepts that facilities can be made safe and that emissions present no serious safety or environmental problems, the location of the proposed plant at one of the three sites appears to be the best alternative. Further, the Board believes that a new plant would not add significantly to the facilities already located at any one of the existing batteries.

The Big Lake site, being heavily treed and located in a low area, is less favourably located having regard for dispersion of SO_2. The site also appears to be located in the Sturgeon River flood plain. It was also noted that the Big Lake battery has the lowest gas production rate and will probably be the first to be abandoned. Therefore if the plant was to be located at this site it would involve transporting more sour gas than would be the case if either of the other battery sites were chosen, the transportation costs would be higher, sour gas pipelines would have to operate for a longer time period, and the plant would have to remain

operating after the production battery was abandoned. Having regard for all of these matters, the Board does not regard the Big Lake site as the most suitable plant location. This narrows the selection to either the proposed St. Albert battery site or the Morinville battery site.

The Morinville battery site has a clear advantage in that it is further removed from residential development than is the St. Albert battery site which is located close to the Silver Chief development. Additionally, the Morinville site is located on relatively flat, untreed land that would provide for good dispersion of SO_2. In this respect it is very similar to the St. Albert site.

In terms of required pipelines, the St. Albert battery currently produces some 60 per cent more gas than does the Morinville battery and additionally, it is expected to have a longer remaining producing life. Accordingly, the St. Albert battery has an economic advantage in that less gas would have to be moved, thus using less fuel. Also, since the St. Albert battery has the longest remaining producing life, a plant at that site would allow the pipeline and other battery to be abandoned when its production ceases. Such would not be the case if the plant was located at the Morinville battery because after production to that battery ended and it was abandoned, the gas plant and pipeline would have to continue operating to handle the St. Albert battery gas.

The distance from the Big Lake battery to the Morinville site is some 1.2 km further than is the distance from the Big Lake battery to the St. Albert site. Locating the battery at the Morinville site would thus increase the cost of conserving gas from the Big Lake battery, and given that the production is relatively small, might render its conservation impractical.

Another factor for consideration, although not of great importance, is the advantage the St. Albert battery site has respecting proximity to the gas sales line.

In summary, the St. Albert battery site has a number of advantages over the Morinville site and indeed is equal to or superior to that site on all counts save one. That factor, however, is an important one in that the St. Albert site is much closer to a number of residences. If the Board was not satisfied that the proposed operation could take place without significant impact on nearby residences, the Board would likely require a more detailed investigation of the alternative site by the applicant before making a decision. As expressed earlier in this report, the Board does not believe significant impacts from the proposed plant would occur. Additionally, the Board notes that even if the plant was located at the Morinville battery site the St. Albert battery would

remain in operation in proximity to the Silver Chief development. The Board believes the incremental impact of the proposed plant compared to that of the existing battery would be modest, and indeed expects that with special efforts it could be negligible.

For the above reasons the Board concludes that the St. Albert battery site is the appropriate location for the proposed gas plant.

OTHER MATTERS

In concluding that the St. Albert site is the best site for the proposed plant, the Board gave weight to Amoco's commitments with respect to special efforts to mitigate the impact on nearby residences. Some of these related to aesthetic matters. Given the distance from the Silver Chief Development, the Board believes that proper attention must be given to these factors to make the plant more acceptable. With these steps, the Board believes the impact may be kept to no greater than that related to the existing battery.

The Board agrees with the interveners that a more comprehensive community contact in education programs should have been undertaken by Amoco prior to the hearing in order to acquaint residents with its plans to develop the batteries and the proposed gas plant. It appears that many of the concerns expressed by the community were not addressed by the applicant until raised at the hearing.

The Board is satisfied with Amoco's undertaking to meet with the community in an effort to alleviate concerns and provide information on its activities in the area and on H_2S and SO_2. The Board also expects Amoco to conduct a baseline noise study and to make its proposed plant at the St. Albert battery complex aesthetically more acceptable. The Board also expects Amoco to ensure that noise from the new facility would only minimally exceed the existing ambient noise level. To ensure that these undertakings, given at the hearing by Amoco, are satisfied, the Board will require Amoco to report to it annually for at least the next three years, outlining the special efforts being made and the success of these efforts. The Board will also request its field staff to regularly visit the area, particularily during the first few years of operation of the proposed plant.

5 DECISION

Having considered all of the evidence of the applicant and interveners, the Board believes that the proposed gas processing plant is in the public interest and that the most appropriate location for the plant is the existing St. Albert battery site. Therefore, the Board intends to approve the applied for plant subject to receipt of the approval of the Minister of the Environment, and to the following special conditions:

- that Amoco report annually for three years, on its efforts to fulfill the commitments given at the hearing,
- that Amoco conduct and make available to the public, baseline noise studies near the plant and in the residential area, and undertake additional monitoring programs during plant operation to ensure noise levels are acceptable, and
- the Board has also requested Alberta Environment to include as part of its Clean Air Act Licence, conditions of operation pertaining to Amoco's commitment to air monitoring, stack design, and emissions.

DATED at Calgary, Alberta on 22 December 1982.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

V E Bohme

V. E. Bohme, P.Eng.
Board Member

E. R. Brushett

E. R. Brushett, P.Eng.
Acting Board Member

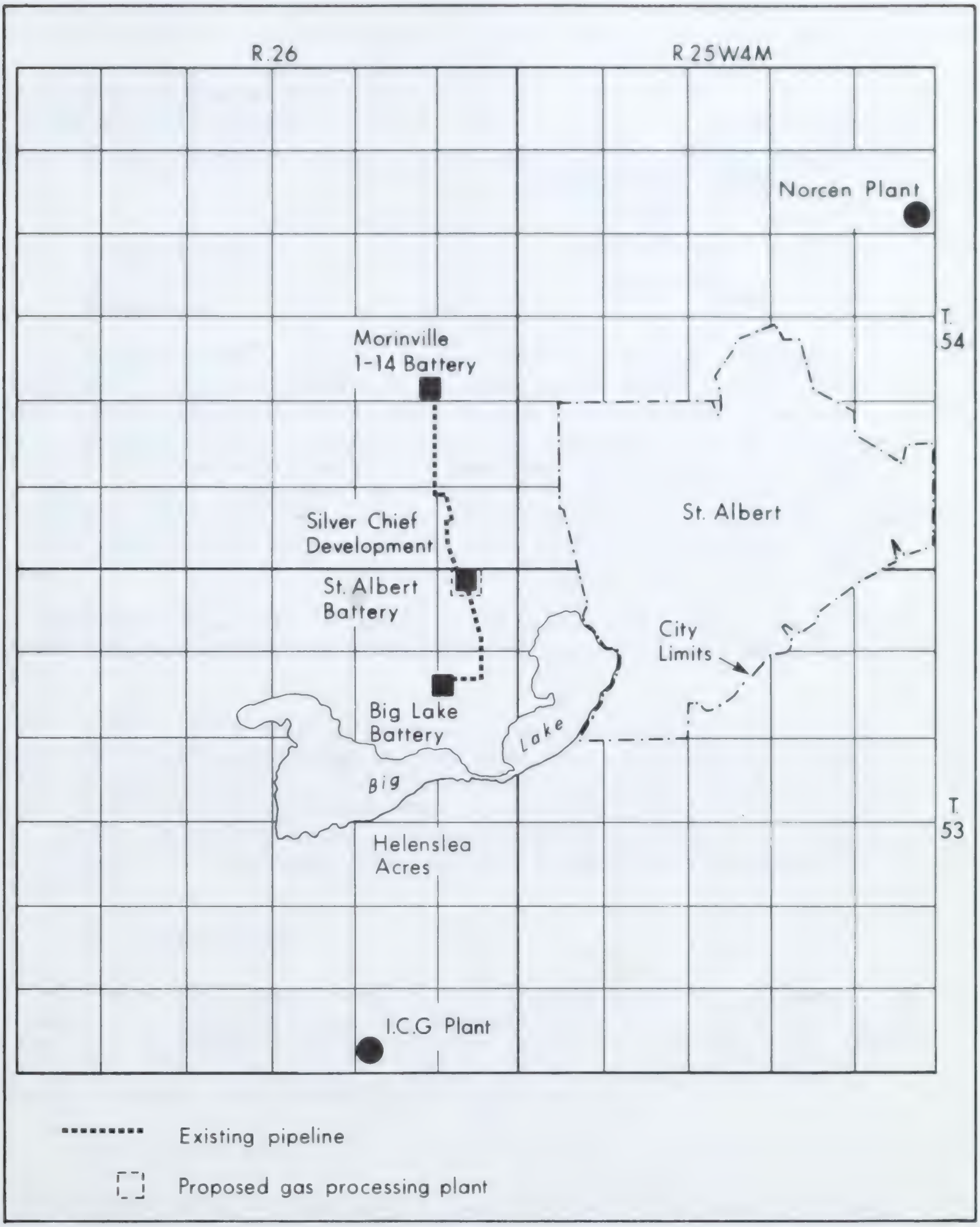


FIGURE 1 ST. ALBERT GAS CONSERVATION PLANT LOCATION MAP

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATIONS BY SUNCOR INC.
TO REINSTATE WELL LICENCE
NUMBERS 97997 AND 97998

Decision 82-40
Applications 821059 and 821060

1 INTRODUCTION

1.1 Background

On 15 October 1982 well licence number 97997 for the well SUNCOR ACHESON EAST 12-30-52-25 and well licence number 97998 for the well SUNCOR ACHESON EAST 4-31-52-25 were issued to Suncor Inc. (Suncor). Suncor proposed to directionally drill the two wells from an existing well site in legal subdivision 14 of section 30, township 52, range 25, west of the 4th meridian (Lsd 14-30-52-25 W4M) for the purpose of obtaining production from the Basal Quartz Sandstone. Suncor indicated it had a right to the surface of the land by way of a surface lease signed with the previous owner of the land, Lewis Farms Ltd., in 1965.

The subsurface locations of the proposed wells, the surface location, and the location of certain other relevant facilities are shown on Figure 1.

On 21 October 1982 a request for a hearing under Section 43(1) of the Energy Resources Conservation Act was made by A. O. Ackroyd on behalf of the present landowners, the Lewis Farms Development Group (Lewis Farms), consisting of Belvedere Developments Ltd., Zukiwski Holdings Ltd., Corvan Investments Ltd., Integrated Building Corp. Ltd., and R.E.L.Peers. On 1 November 1982 the well licences were suspended by the Board.

1.2 The Applications

On 23 November 1982 Suncor applied to reinstate both well licences. In its applications it indicated the proposed wells were within the limits of the City of Edmonton (City) and that Suncor had, in accordance with ERCB Interim Directive ID 81-4, requested the consent of or other comments from the City regarding the applications.

1.3 The Interventions

On 29 November 1982 an intervention was filed with the Board on behalf of Lewis Farms. The intervention suggested that a recent acceleration in drilling in the area indicated a piecemeal approach to mineral development and that this would be detrimental to future urban development. The intervention requested that the Board hold the

applications in abeyance until it had decided whether a public inquiry should be held to allow for input from the mineral and surface owners in the west Edmonton area with respect to adopting a long-range plan for integrated development of both the minerals and the surface.

The City also intervened at the hearing and indicated that it had no objections to Suncor's applications subject to certain conditions being met.

1.4 The Hearing

On 30 November 1982 at Edmonton, Alberta, a public hearing of the applications was held with G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and E. R. Brushett, P.Eng., sitting.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Suncor Inc. (Suncor) D. Lane	A. D. Brown, P.Eng. C. W. Weeks, P.Geol. S. Collins, P.Eng. W. Thomas P. G. Kingston
Belvedere Developments Ltd. Zukiwski Holdings Ltd. Corvan Investments Ltd. Integrated Building Corp. Ltd. R.E.L. Peers (Lewis Farms Development Group) A. O. Ackroyd, Q.C.	M. McCullough J. Steil
The City of Edmonton M. McAvoy	W. Cameron
Energy Resources Conservation Board staff M. J. Bruni M. Semchuck G. D. Agnew	

2 REQUEST FOR A GENERAL INQUIRY

Prior to the release of this report, the Board decided to hold an inquiry as requested by the interveners at the subject hearing and in connection with other applications currently before the Board.

The Board held a pre-inquiry meeting on 21 December 1982 in Edmonton, and issued a Memorandum of Decision following the meeting. In the memorandum the Board stated that it would expect to defer decisions respecting applications currently before it for energy facilities in the area of the inquiry "...unless it is satisfied that a particular application would not be critically related to the matters to be considered at the inquiry". Since the applied-for wells would be in the inquiry area, this decision report will address not only the question of whether the well licences should be reinstated, but also whether the applications should be held in abeyance until the results of the general inquiry are known.

3 CONSIDERATION OF THE APPLICATIONS

3.1 Views of Suncor

Suncor stated the subject wells are required in the northwest quarter of section 30 and the southwest quarter of section 31 to evaluate the hydrocarbon potential of its leases in all formations down to and including the Ellerslie Formation. It estimated that drilling the proposed 12-30 well would allow approximately 36 10^3 m^3 of recoverable reserves to be produced. Suncor's cumulative production estimate for the 4-31 well is approximately 27 10^3 m^3. The applicant indicated that these reserves would otherwise be lost as they could not be recovered by adjacent existing wells.

Suncor advised that it chose the more costly directional drilling from its existing 14-30 well site for the proposed 12-30 and 4-31 wells in order to minimize impact on the surface. Suncor endeavoured to obtain an additional 0.4 hectares (1.03 acres) of surface land adjoining its existing well site because it believed initially that this additional area would be required as temporary working space for its drilling operations. Subsequently it decided to drill the subject wells from within the boundaries of the existing 14-30 well site without additional surface land area. It maintained that this would cause minimal impact considering that it would not require additional land and that it would consolidate the surface equipment required to produce the wells. This consolidation of production facilities would help reduce visual impact. Suncor advised it had agreed to substitute quieter electric motors for gas-driven engines on the pumping units. It has applied to the City for power.

Suncor stated that all production from the applied-for wells would be transmitted through an existing flowline which extends from the 14-30 site to its existing battery in 7-31, resulting in no new production facilities or flowlines. Following separation at the existing 7-31 battery the oil and gas would be transported, processed, and sold through existing facilities in the area. Suncor said that it has a solution-gas contract with Inter-City Gas Corporation (I.C.G.) for its gas. Suncor estimated the subject wells would jointly produce about

1.7 10^3 m^3 per day of solution gas, and since an I.C.G. representative had indicated to Suncor that the existing plant could process an additional 8.5 10^3 m^3 per day of solution gas, concluded that its additional volumes of solution gas could be adequately processed.

Suncor stated that it would comply with the City's requirements regarding the subject well site. These requirements, effective the time urban development begins on land immediately adjacent to the site, are as follows:

a) replace all gas-driven pumping motors with electric motors,

b) erect chain-link fencing with interwoven plastic screen, and

c) comply with development standards as specified in the land use by-law for the area, and conform with nuisance and noise by-laws.

The applicant advised it would relocate its existing flowlines in the area at the request of surface land developers if the developers accepted the costs for such relocation. It would also consider rerouting its existing access roads in the area, and reducing the size of some of its existing well sites. It has already conducted surveys with these objectives in mind. Suncor concluded that, with its commitments to reduce the size of existing well sites, upgrade the aesthetics of its existing facilities, and confine its proposed new operations to the existing 14-30 well site, future surface land development in the subject area could be reasonably accommodated.

Suncor opposed the suggestion that its applications be held in abeyance pending the outcome of a possible inquiry on the basis that it had voluntarily committed itself to upgrading its operations in the area, and that such measures satisfied essentially all factors likely to arise at an inquiry. It also contended that Lewis Farms had not demonstrated adverse effects related to the proposed wells.

3.2 Views of Lewis Farms

Lewis Farms did not dispute that Suncor is entitled to win the minerals on lands for which it holds or has an agreement to acquire the mineral rights. It stated that it did not oppose the drilling of Suncor's wells but it was concerned that the proposals represented a less-than-optimal approach. Consequently it believed the applications should be held in abeyance pending a comprehensive review not only of the urban uses of the surface land but also of the oil and gas uses and the interrelationships of the two, for the betterment of both groups of owners.

Lewis Farms agreed with the general principles of Suncor's mitigative measures but noted that the applicant had not made any specific commitments as to when it would implement its mitigative measures to reduce impact. It questioned Suncor's position that the existing I.C.G. gas plant would have sufficient capacity to adequately process the additional solution gas that would result from the applied-for wells. It presented evidence that suggested the I.C.G. gas plant was close to its limit on SO_2 emissions, nearing its full capacity, and contended that at these peak levels some of the gas would periodically be backed out and flaring would occur at the batteries.

Lewis Farms stated that, provided extensive codes with detailed requirements and specific standards were established for integration of the various surface land uses in the area, it was likely that energy facilities could be safely operated in an urban setting.

Much of the evidence from Lewis Farms dealt with the need for an inquiry. Since an inquiry has been called, the Board is not dealing extensively with such evidence in this report. Lewis Farms did conclude that the Board should hold Suncor's subject applications in abeyance pending a decision with respect to an inquiry. It based its position on the view that approval of the applications would preclude the possibility of modifying the current plans of Suncor to make its proposed developments more consistent with other existing or planned facilities in the area.

3.3 Views of the City

The City expressed agreement with the request by Lewis Farms for a general inquiry. It stated that it had no objections to the Suncor applications provided that Suncor would comply with certain conditions when urban development began on lands immediately adjacent to the well site. The conditions have been listed earlier in section 3.1 of this report.

The City further stated that it believed Suncor's intended use of existing facilities would prove consistent with the result of an inquiry into future energy and surface development. The City thus saw no reason to delay a decision on Suncor's applications until after a possible inquiry had taken place.

3.4 Views of the Board

The Board agrees with the applicant that the wells are needed to recover additional reserves of oil within the Acheson East Blairmore B Pool which, if they exist, could not be drained by existing wells in

the pool. The Board did not receive evidence that disputes this need nor the right of the applicant to win its minerals. The Board notes that, for these reasons, the City did not object to Suncor's applications:

a) the applicant committed to the conditions set out by the City,

b) it would use an existing well site and existing production facilities and pipelines, and

c) it would accelerate depletion of the existing reserves in the area.

The Board has concluded on the basis of the evidence at the hearing that the proposed wells would create essentially no additional disturbance in the area, and would have no significant incremental impact on the surface, residents of the area, or the environment. This is due primarily to the commitments made by Suncor and is dependent on its adherance to those commitments. Since the incremental impact would be negligible and given that the wells would drain additional reserves not otherwise recoverable, the Board, with one modest reservation, sees no reason to deny the applications.

The only remaining area of concern to the Board is that the extra gas production from the proposed wells might not be accommodated by the nearby I.C.G gas plant. The Board notes that the applicant had not discussed this matter with I.C.G since before the hearing. The Board agrees with Lewis Farms that if capacity were not available, and this resulted in the flaring of slightly sour gas in the area, significant impacts could occur. The Board would therefore not reinstate the well licences until such time as Suncor had satisfied the Board that plant capacity would be sufficient to handle the gas produced from the proposed wells.

With respect to the request that the applications be held in abeyance until the results of the general inquiry are known, the Board does not believe this is necessary. As stated earlier, the drilling and completion of the wells would have little, if any, incremental impact on future surface development in the area because of the proposed use of existing surface leases, pipelines, and production facilities. In this respect, the Board agrees with the City that Suncor's applications are consistent with what might be expected in the way of guidelines resulting from the inquiry. Also, Suncor expects to have to comply with any regulatory standards promulgated in the future.

4 DECISION

The Board will reinstate well licences 97997 and 97998 upon Suncor satisfying it that sufficient processing capacity is available at the I.C.G. plant for the gas that will be produced from the subject wells.

ISSUED at Calgary, Alberta, on 12 January 1983

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

E. R. Brushett

E. R. Brushett, P.Eng.
Acting Board Member

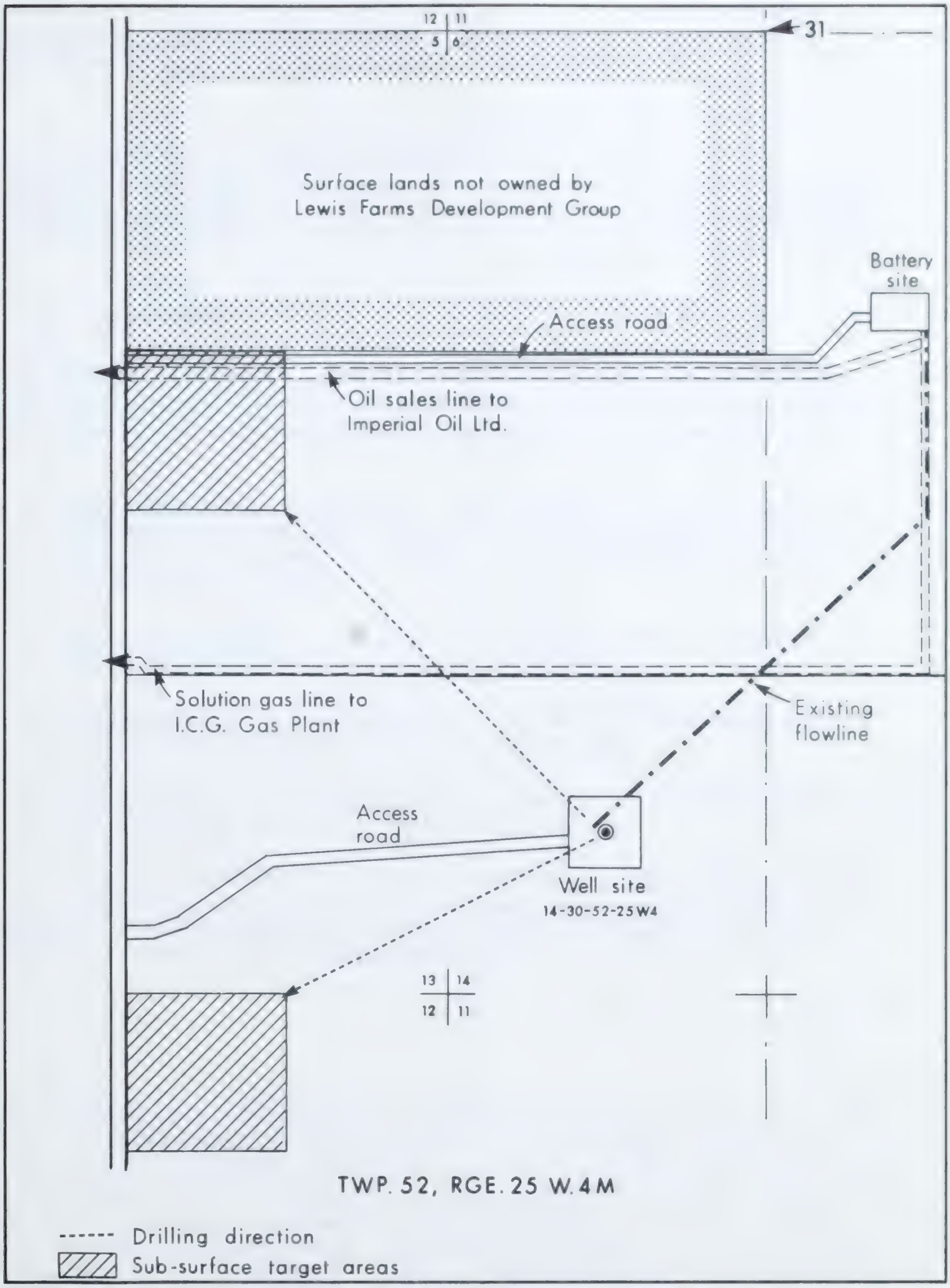


FIGURE 1 SUB-SURFACE TARGET AREAS AND EXISTING FACILITIES IN THE AREA OF APPLICATION.

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY NOVA, AN ALBERTA CORPORATION
FOR A PERMIT TO CONSTRUCT PIPELINES
IN THE HEART RIVER AREA

Decision 82-41
Application 820940

1 THE APPLICATION

NOVA, An Alberta Corporation, applied pursuant to the Pipeline Act to construct four laterals in the Watino-McLennan area. They would consist of the following and each would have a meter station at its receipt point:

- Heart River (main) lateral: approximately 45 km of 273.1 mm pipe and 44 km of 168.3 mm pipe, from legal subdivision 5 of section 11, township 77, range 16, west of the 5th meridian to Lsd 6-36-77-25 W5M.
- McLennan lateral: approximately 19 km of 114.3 mm pipe from Lsd 9-22-79-20 W5M and Lsd 6-28-77-20 W5M.
- Roxanna lateral: approximately 11.2 km of 114.3 mm pipe from Lsd 10-27-78-19 W5M to Lsd 14-24-77-19 W5M.
- Donnelly lateral: approximately 7 km of 114.3 mm pipe from Lsd 2-1-77-21 W5M to Lsd 6-25-77-21 W5M.

In addition, at the hearing Nova filed an amendment that would modestly shift portions of the Heart River lateral further away from the Village of McLennan. It also stated that it had signed agreements with the owners of each of the land parcels affected.

2 THE HEARING

The applications were considered at a public hearing on 30 November 1982 in Fahler, Alberta, with N. Strom, P.Eng., L. A. Bellows, P.Eng., and E. G. Fox, P.Eng., sitting. Those who appeared at the hearing are shown in the following table. Interventions were received from the Smoky River Surface Rights Society, a group of three landowners (Lapointe, Gauthier, and Garant) represented by Mr. R. Carter and Bralorne Resources Limited. At the opening of the hearing Mr. Carter, indicated that Nova had reached agreement with Messrs. Gauthier and Garant, leaving only the third landowner, R. Lapointe, with certain objections.

THOSE WHO APPEARED AT THE HEARING

Principal and Representatives (Abbreviations used in Report)	Witnesses
NOVA, An Alberta Corporation (Nova) H. D. Williamson	W. J. Litvinchuk, P.Eng. F. T. Barlage, P.Eng. K. Exner Dr. B. Lee, P.Eng. R. Buchanan K. Walker R. G. Marshall, P.Eng. (R. G. Marshall Engineering and Construction Ltd.)
Bralorne Resources Limited J. R. Richardson	
Smoky River Surface Rights Society (Society) H. Dion	H. Dion L. Duby A. Briand
R. Lapointe R. Carter	Mr. & Mrs. R. Lapointe
Alberta Environment T. Bosenberry	
Energy Resources Conservation Board staff G. C. Dunn, P.Eng. J. K. Moloney	

3 PRELIMINARY DECISION

Having regard for evidence submitted by Nova and the consensus of the landowners that there was a strong preference for winter construction, it was clear to the Board that an early decision was necessary. Nova indicated that winter construction was strongly preferred in this case since landowners had particularly requested it and also a considerable amount of pipeline had to be constructed in muskeg and wet areas where summer construction was not practical. To allow construction to be completed on frozen ground, Nova indicated that it would be necessary to have a permit prior to 24 December 1982. This would allow some two months for construction, and provide sufficient lead time for necessary surface rights aquisition.

On behalf of its members, the Society expressed a strong preference for winter construction.

The Board concluded that, aside from a portion of the McLennan lateral, the suitability of the routes including the Smoky River crossing location had been demonstrated. Therefore, having heard all the evidence presented by Nova, including that adduced through cross-examinations by Alberta Environment, the Society, and R. Lapointe, the Board announced at the conclusion of the hearing that it was essentially satisfied with most aspects of the application for the Heart River, Donnelly, and Roxanna laterals and that it had decided to grant the permit for those laterals.

The Board intends to issue a permit for the applied-for pipelines, excluding the McLennan lateral, subject to receiving approval from the Minister of the Environment, including any conditions he may choose to attach. The permit will also be subject to such special conditions as the Board may deem appropriate, having regard for the concerns of the interveners.

Therefore, the Board would expect Nova to proceed immediately upon receiving the permit so that all construction would be completed while the ground was frozen.

In relation to the southern leg of the McLennan lateral, the Board had regard for the particular land use, agricultural impact, and environmental problems brought forward by Mr. R. Lapointe. It was clear to the Board that the evidence relating to those concerns would have to be examined in more detail by the Board in order to reach a decision respecting the acceptablility of the proposed route for the McLennan lateral. Similarly the Board noted that the intervention by the Society addressed a set of concerns applicable to agricultural impacts of pipeline construction and reclamation that would have to be addressed on the merits of the evidence.

The Board, though generally satisfied that environmental concerns, including those of impact on agricultural land, were extensively addressed by Nova, concluded that two remaining issues required further attention. The subsequent sections of the report therefore deals with these two issues:

(1) Impact on agricultural land, and

(2) Suitability of the applied-for route of the McLennan lateral.

4 IMPACT ON AGRICULTURAL LAND

4.1 Intervener's Views

The Society presented five proposals in its intervention and spoke to these concerns in some detail during the hearing. The Society requested the Board consider the following items:

(a) Construction be done during the winter to reduce soil damage and disruption to farm operations.

(b) Require a period of shut down of construction should wet or muddy conditions develop during construction.

(c) Require stripping of top soil over the area of the actual ditch only.

(d) Allow provisions for future farm development without cost or penalty to the farmer; e.g. surface ditches, subsurface drainage or deep plowing.

(e) Appoint a local representative, familiar with farmers and farm conditions in the municipal district to mediate issues or problems related to farmland during actual construction.

The Society also acknowledged the need to develop the natural resources and in fact went on record as not opposing the pipeline. The main thrust of the Society was to allow the energy-related development to proceed with minimum inconvenience or hardship to the farm operators.

On the first four matters the Society expanded its position somewhat and in general seemed to gain some satisfaction from the evidence provided by Nova. In particular, the Society appeared satisfied that Nova intended to construct the pipeline on frozen ground and would minimize soil disturbance by stripping above the ditch area only. Although the Society acknowledged the undertaking by Nova to shut down construction during wet and muddy periods - a remote possibility for winter construction - it expressed concern that the undertaking may not be fulfilled. The Society believed that the implementation of this guarantee would require the presence of a local mediator with the knowledge to judge conditions and the power to curtail activities. The group also expressed the concern that the Land Conservation and Reclamation Council (Reclamation Council) could not provide adequate surveillance and mediation as their representative was often not available when necessary.

On the matter of future farm development, the Society seemed generally satisfied that the initial routing and planning was being undertaken with as much foreknowledge as practically possible. It made no specific recommendations as to the depth of pipeline burial or route considerations, but did state its belief that any future farm development requiring pipeline relocation or modification should be able to proceed at no cost to the farmer.

4.2 Nova's Views

Nova replied to the Society approximately in the following manner:

(a) It indicated a strong preference for winter construction in part because of that preference by the landowners.

(b) It agreed to shut down construction should it encounter wet or muddy conditions where it appeared construction would damage the soil.

(c) It said it intended to strip topsoil from above the ditch only, using its modified rotary rocksaw machine. Furthermore, Nova said that it would attempt to comply with farm operator requests in making adjustments where necessary in that procedure.

(d) Regarding farm development, Nova said it had made every attempt to route the pipelines to minimize land surface disturbance and, further, that it would co-operate in meeting the specific requests of landowners when those were identified prior to construction. The applicant did not believe that it was suitable or practical for it to assume sole responsibility for the resolution of conflicts between pipeline location and any and all possible future farmland development.

(e) Respecting construction surveillance, Nova stated that it would have an environmental inspector continuously on site, authorized to oversee topsoil stripping and preservation and to ensure that no environmental damage was occurring. Nova stated that the environmental inspector would make every effort to co-operate with a landowner's wishes when the landowner identified a problem area. Nova also confirmed that the environmental inspector would have the authority to shut down construction as an environmental safeguard if and when necessary.

4.3 Board's Views

Having considered the evidence presented, the Board is generally satisfied with Nova's intended practice concerning winter construction, curtailment of construction during wet or muddy conditions, and topsoil conservation.

The Board notes and concurs with the participants' unanimous agreement regarding the construction schedule. To fully ensure that construction or reclamation does not occur during wet or muddy conditions the Board agrees that a general condition to this effect should be included in the pipeline permit.

The Board is satisfied with the methods of topsoil conservation proposed by Nova. While it noted Alberta Environment's questions respecting the

possibility of topsoil and subsoil mixing during stripping, it believes that satisfactory control can be obtained using the modified rotary rocksaw stripper and adjusting the depth of cut to avoid mixing the soil horizons.

In connection with the Society's request concerning future farm development, the Board notes the comments of Nova that as a matter of practice it has attempted to accommodate all individual landowner requests. The Board also observes that it is not of practical value to look at the possibility of conflicts of the installed pipeline with hypothetical future farm developments. The Board therefore concludes that the Society's concern is more conceptual than specific and cannot be addressed in any practical manner. The Board notes there is provision in the Pipeline Act to deal with future alterations of pipelines where such changes are well-justified and in the public interest.

The Board has also carefully considered the Society's request to appoint a local representative to mediate problems during construction. The Board notes that the Society was primarily concerned with availability of the local Reclamation Council representative. The Board therefore will refer the matter to the Land Conservation and Reclamation Council and ask that it ensure the availability of its representatives prior to and during construction and reclamation.

The Board perceives that in part, the problem raised by the Society is one of communication between affected parties. If each landowner is aware of the construction schedule generally and is advised of the date of entry upon a particular property, and if there is clear identification to a landowner of the resident Nova environmental inspector, and also if the means of contacting the Reclamation Council's inspector and the Board's pipeline inspectors are well understood, the Board believes that the necessary communication mechanism will be fully effective.

In regard to the communication arrangements and having regard for soil conservation, the Board immediately following the hearing directed its staff to arrange a meeting to provide landowners with information regarding soils management, surveillance by Nova, the Reclamation Council and the Board; and the integrated communication process that would be used. The agenda for this meeting, which will take place in Fahler on 17 December 1982, is shown in the attachment to this report.

5 ROUTE OF THE MCLENNAN LATERAL

5.1 Intervener's Views

Mr. Lapointe stated that he was opposed to the southern leg of the Nova route for the McLennan lateral because it would result in the installation of an above-ground valve facility in the centre of section 28, all of which land he farms (see Figure 1). He also expressed serious

concern that the pipeline construction might cause unacceptable water quality deterioration because it could interfere with the drainage pattern to dugouts in the northern half of section 33. Farms in this area are obliged to rely upon dugouts as the sole source of potable water, and protection of that supply both in terms of quality and quantity could not be put in jeopardy. In addition Mr. Lapointe indicated that he had two sons each of whom would need to establish a residence, and he could think of no better place for those residences than in the northwest quarter of section 33 along the highway.

Mr. Lapointe suggested an alternative route 1.5 km (1 mile) west of Nova's proposed route, going north from the centre of section 29 (see figure) which would alleviate his routing concerns. He stated that such a route would mean that the above-ground valve would be located in the NW corner of the SE quarter of section 29, still on his land, but at the corners of separately owned property. The effect should be less interference with farming operations and, in addition, the route would avoid crossing Mr. Lapointe's home quarter, the northwest quarter of section 33. Also he noted that his suggested alternative route would be no longer than Nova's proposed route.

5.2 Applicant's Views

Nova stated that, in selecting the McLennan lateral route, it had minimized impact on agricultural land by aligning it along quarter-section boundaries and through muskeg where possible. Nova claimed it had been unaware of Mr. Lapointe's route location objections until November 22 despite periodic meetings with Mr. Lapointe dating back some seven months. Nova indicated that once it received Mr. Lapointe's intervention it contacted landowners along Mr. Lapointe's suggested alternative route and had encountered opposition to that route by another landowner, Mr. Maisonneuve, in the southern half of section 32.

Nova stated that it has constructed many pipelines in the vicinity of dugouts without interferring with the dugout water supply and believed there was no reason to expect water quality or quantity problems as suggested by Mr. Lapointe.

Nova indicated that the above-ground valve location in the centre of section 28, 5 metres (16 feet) by 8.3 metres (26 feet), would be enclosed by a steel fence and that access to the site for routine inspection and servicing would be on foot. Nova also pointed out that Mr. Lapointe currently farms around other similar obstructions and that the valve location would present minimum inconvenience.

Nova stated that it believes the route selected for the McLennan lateral is the best route available and that the route suggested by Mr. Lapointe would simply transfer the impact of the pipeline from one landowner to others.

5.3 Board's Views

The Board has reviewed the potential environmental impact of the McLennan lateral and concludes that Nova has provided insufficient evidence to demonstrate that all viable alternatives and mitigative measures have been adequately dealt with. Although Mr. Lapointe suggested a route that might be a viable alternative, the impact of this alternative could not be adequately considered due to the lack of detail available and the fact that affected landowners were not present at the hearing.

The Board is of the view that if a negotiated settlement, including provision for adequate mitigative measures, cannot be reached between Mr. Lapointe and Nova, the route of the McLennan lateral will have to be reconsidered with all viable alternatives presented. If, on the other hand, a settlement can be reached on the route applied for, a further hearing would not be required.

6 DECISION

The Board grants the application for a pipeline permit for the Heart River lateral system as submitted by Nova, with the exception of that portion identified as the McLennan lateral and meter station. The permit will be issued with the condition that no construction occur during wet or muddy conditions and will be subject to the approval of the Minister of the Environment with respect to environmental matters.

The Board denies without prejudice the McLennan lateral portion of Application 820940.

ISSUED at Calgary, Alberta, on 15 December 1982.

ENERGY RESOURCES CONSERVATION BOARD

N. Strom, P.Eng.
Board Member

L. A. Bellows, P.Eng.
Acting Board Member

E. G. Fox, P.Eng.
Acting Board Member

ATTACHMENT

SOIL HANDLING AND RECLAMATION SEMINAR
NOVA's HEART RIVER LATERAL PROJECT

17 DECEMBER 1982
SMOKY RIVER FISH AND GAME ASSOC. LOG CABIN -
FAHLER, ALBERTA

PROGRAM

09:30-12:00 W. McGill, Ph.D., Department of Soil Science, University of Alberta

Topic - "Soils and Their Response to Surface Disturbance"

- o soils and their characteristics;
- o productivity vs capability; and
- o response of soils to surface disturbance.

10:30 Coffee

12:00-13:00 Lunch

13:00 L. Marciak, Soils Branch, Alberta Agriculture

Topic - "An Overview of Soil Handling and Reclamation Resulting from Pipeline Construction".

13:30 Nova, An Alberta Corporation

Topic - "Soil Handling and Reclamation on the Heart River Lateral Pipeline Project".

- o description of the soil stripping process;
- o soil handling during construction; and
- o reclamation of the soil.

14:30 Coffee

15:00 J. North, Land Conservation and Reclamation Council, Peace River

Topic - "Discussion of Soil Reclamation in the Peace River Area"

- o discussion of practices used in the area and their ultimate affect upon reclamation; and

- o reclamation standards.

15:30 A discussion of who the landowner contacts if he is concerned about soil handling on his property during construction.

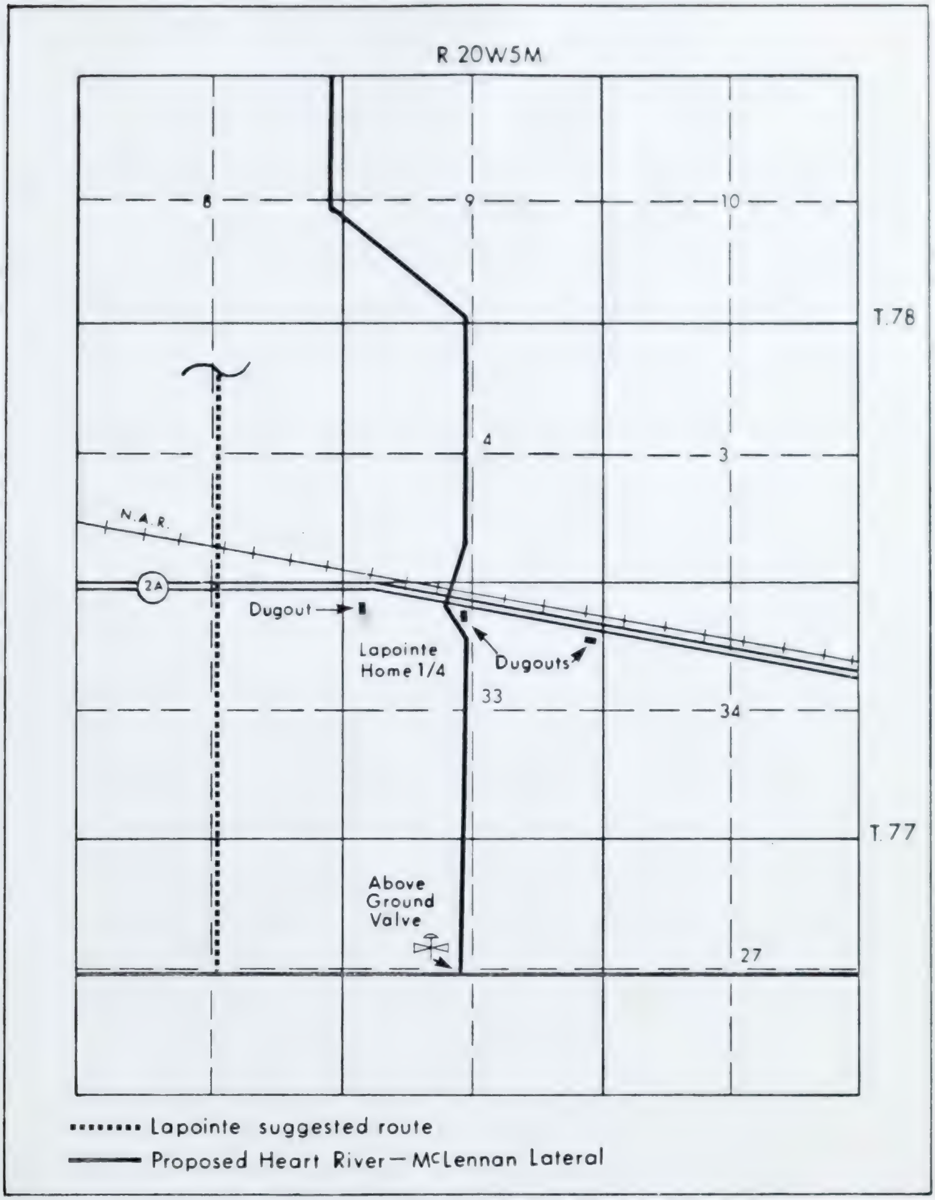


FIGURE 1 SOUTH PORTION — McLENNAN LATERAL

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA CANADA